IN THE UNITED STATES DISTRICT COURT
FOR THE WESTERN DISTRICT OF PENNSYLVANIA

COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION, STATE OF CONNECTICUT, STATE OF MARYLAND, STATE OF NEW JERSEY, and STATE OF NEW YORK,	:	Electronically Filed
Plaintiffs,	:	
v.	:	Civil Action No. 2:05cv0885
ALLEGHENY ENERGY, INC., ALLEGHENY ENERGY SERVICE CORPORATION, ALLEGHENY ENERGY SUPPLY COMPANY, LLC, MONONGAHELA POWER COMPANY, THE POTOMAC EDISON COMPANY, and WEST PENN POWER COMPANY,	:	Chief District Judge Gary L. Lancaster
Defendants.	:	

PLAINTIFFS' POST-TRIAL PROPOSED FINDINGS OF FACT (LIABILITY PHASE)

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Plaintiffs Pennsylvania Department of Environmental Protection ("PA DEP") and the States of Connecticut, Maryland, New Jersey and New York respectfully submit the following proposed findings of fact in the above-captioned matter.

I. THE DEFENDANTS

A. Allegheny Energy

1. Defendant Allegheny Energy, Inc. ("Allegheny Energy") is a public utility holding company that owns the five other defendants in this action: Allegheny Energy Service Corporation ("Allegheny Service"), Allegheny Energy Supply Company ("Allegheny Supply"), Monongahela Power Company ("Monongahela"), the Potomac Edison Company ("Potomac") and the West Penn Power Company ("West Penn"). Docket Item 430 ¶ 1.

2. Allegheny Energy was previously known as Allegheny Power System, Inc. until a corporate name change occurred in September, 1997. PTX 24 at 6. For the purposes of these proposed findings of fact, references to "Allegheny Energy" include that entity operating under that previous name.

3. Allegheny Energy also owned all or substantially all of Allegheny Service, Monongahela, Potomac and West Penn, and/or their corporate predecessors, at the time of each project at issue in this litigation. Docket Item 430 ¶ 2; DTX 666 at AE_HQ_00669008.

4. In 2006-2007, Allegheny Energy owned 100 percent of Allegheny Service, Monongahela, Potomac and West Penn, as well as 98.61 percent of Allegheny Supply. DTX 666 at AE_HQ_00669006-07.

5. Allegheny Energy is an integrated energy business that owns and operates electric generation facilities. PTX 1 ¶ 30; PTX 2 ¶ 30.

6. While each of Allegheny Energy's three electric utility subsidiaries, Monongahela, Potomac and West Penn, is separately incorporated, they operate under the same trade name: Allegheny Power. PTX 1 ¶ 30; PTX 2 ¶ 30.

7. Allegheny Energy derived substantially all of its income from its subsidiaries, including Monongahela, Potomac and West Penn, for the years 1993 through 1999. PTX 20-PTX 26 at Part 1, Item 1.

8. In 1999, Allegheny Energy also derived its income from Allegheny Supply. PTX 26 at Part 1, Item 1.

9. The senior executives, including officers and directors, of Allegheny Energy were paid in part based on their work for the subsidiaries including Monongahela, Potomac, West Penn, and Allegheny Service for the years 1993 through 1999. PTX 36 - PTX 42 at Item 6.

10. Since 1999, Allegheny Energy has continued to operate its business through its subsidiaries, including Monongahela, Potomac, West Penn, Allegheny Supply and Allegheny Service, to the present. PTX 26 – PTX 35 at Part 1, Item 1.

B. <u>**Allegheny Service**</u>

11. Allegheny Service is a wholly-owned subsidiary of Allegheny Energy that provides management and professional services to Allegheny Energy, Allegheny Supply, Monongahela, Potomac, and West Penn, including accounting, administrative, information systems, environmental, engineering, financial, legal, maintenance and other services. PTX 1 ¶ 24; PTX 2 ¶ 24.

12. Allegheny Service was previously known as Allegheny Power Service Corporation until a corporate name change occurred on July 16, 1999. PTX 42 at AE_DUN_00571622; D.T. (Daniel Dunlap 30(b)(6) witness on corporate organization), at

19:19-25. For the purposes of these proposed findings of fact, references to "Allegheny Service" include that entity operating under that previous name.

13. Allegheny Service employed Allegheny Energy's officers for the years 1993 through 2007. PTX 20 – PTX 35 at Part 1, Item 1.

14. Allegheny Energy has no employees of its own, and up until 1997 the employees serving the Allegheny entities were employed by Allegheny Service or by the operating subsidiaries Monongahela, Potomac, and West Penn. *See* PTX 20 – PTX 35 at Part 1, Item 1.

15. By 1998, Allegheny Service had become the employer of substantially all of the other Allegheny entities' employees. PTX 25 – PTX 35 at Part 1, Item 1.

16. In 1995, Larry Meyers, the director of environmental services for Allegheny, was employed by Allegheny Service. D.T. (Peter Skrgic 30 (b)(6) witness on corporate organization), at 60:03-61:01.

17. By the end of 1998, all Allegheny Power employees of the various entities were employed by Allegheny Service. *See* PTX 20 – PTX 35 at Part 1, Item 1; D.T. (Daniel Dunlap 30(b)(6) witness on corporate organization), at 39:02-14.

18. The employees of Allegheny Service communicate directly with state and federal regulators with respect to environmental and other issues involving Allegheny Energy, Allegheny Supply, Monongahela, Potomac and West Penn. PTX 1 ¶ 30; PTX 2 ¶ 30.

C. <u>Allegheny Supply</u>

19. At all times pertinent to this action, Allegheny Supply was an owner of the Armstrong, Hatfield's Ferry and Mitchell power stations. PTX 1 ¶ 3; PTX 2 ¶ 3.

20. By 2007, the entire coal-fired generating capacity of the Hatfield's Ferry, Armstrong and Mitchell power stations was owned by Allegheny Supply. PTX 35 at 16.

D. Monongahela

21. At all times pertinent to this action, Monongahela was an owner of the Armstrong, Hatfield's Ferry and Mitchell power stations. PTX 1 ¶ 3; PTX 2 ¶ 3.

22. In 1996, Monongahela owned 456 of the total of 1,660 megawatts of coal-fired generating capacity at the Hatfield's Ferry plant. PTX 23 at 15 of pdf (page 16 of original document).

E. Potomac

23. Until August 1, 2000, Potomac participated in the operation of, and partially owned the Hatfield's Ferry plant. PTX 1 ¶ 27; PTX 2 ¶ 27.

24. In 1996, Potomac owned 332 of the total of 1,660 megawatts of coal fired generating capacity at the Hatfield's' Ferry plant. PTX 23 at 15 of pdf (page 16 of original document).

F. **West Penn**

25. Until November, 1999, West Penn operated and owned the Armstrong facility and the Mitchell facility; and, until November, 1999, West Penn also participated in the operation of, and partially owned, the Hatfield's Ferry facility. PTX 1 ¶ 28; PTX 2 ¶ 28. D.T. (Daniel Dunlap 30(b)(6) witness on corporate organization), at 34:01-24.

26. In 1996, West Penn owned 872 of the total of 1,660 megawatts of coal-fired generating capacity at the Hatfield's Ferry plant. PTX 23 at 15 of pdf (page 16 of original document); D.T. (Daniel Dunlap 30(b)(6) witness on corporate organization), at 34:01-24..

27. In 1996, West Penn owned all of the coal fired generating capacity at the Armstrong plant and all of the coal fired generating capacity at the Mitchell plant. PTX 23 at 15 of pdf (page 16 of original document).

28. Each defendant in this action is a "person," as that term is defined in 42 U.S.C. § 7602(e). Docket Item 430 ¶ 3.

II. COAL-FIRED ELECTRIC GENERATING UNITS

A. General Information About How Coal-Fired Generating Units Work

29. A coal fired power plant burns coal to heat water that turns into steam and spins a turbine to turn a generator to produce electricity. T.T., Sept. 13, 2010, at 44:1-5..

30. The coal is ground to a fine powder in pulverizers. T.T., Sept. 13, 2010, at 46:15-25.

31. Pulverized coal and air are blown into the inside of the boiler's furnace through burners. The air contains oxygen which is necessary for the coal to burn in the boiler. T.T., Sept. 13, 2010, at 47:13-18, 48:5-10.

32. The inside of the boiler furnace walls are known as waterwalls because they are composed of tubes with water flowing through them. T.T., Sept. 13, 2010, at 49:1-7.

33. Heat from the burning coal heats the water in the waterwall tubes surrounding the furnace and turns it into steam. T.T., Sept. 13, 2010, at 48:14-21, 49:3-15.

34. A header is a large cylinder which collects steam from the numerous tubes in a component, and sends that steam in a single stream to the next component. T.T., Sept. 20, 2010, at 25:16-26:17.

35. A "subcritical" boiler operates at a pressure below 3,200 pounds per square inch (psi), utilizing a process where steam and water are mixed together, requiring separation in a steam drum. T.T., Sept. 13, 2010, at 56:16-57:8.

36. In a subcritical boiler, the waterwall tubes lead to the steam drum, where the water and steam are separated. T.T., Sept. 13, 2010, at 49:8-19.

37. Water separated in the steam drum returns to the boiler for further heating. T.T., Sept. 13, 2010, at 49:8-19.

38. A "supercritical" boiler operates at a pressure greater than 3,200 psi, utilizing a process where all of the water turns to steam. T.T., Sept. 13, 2010, at 56:16-57:8.

39. The Armstrong and Mitchell boilers are "subcritical;" the Hatfield's Ferry boilers are "supercritical." T.T., Sept. 13, 2010, at 56:19-57:2.

40. After leaving the waterwalls and/or steam drum, the steam then travels through other tubes, called superheaters, where it is further heated and achieves the temperature and pressure needed to turn the turbine. T.T., Sept. 13, 2010, at 49:3-25.

41. The steam leaves the superheater and turns the high pressure turbine. T.T., Sept. 3, 2010, at 49:21-25.

42. The turbine turns the generator, which converts the mechanical energy of the turbine into electricity. T.T., Sept. 13, 2010, at 56:4-8.

43. After traveling through the high pressure turbine, the steam returns to the boiler and travels through tubes called reheaters, which increase both the temperature and pressure of the steam. T.T., Sept. 13, 2010, at 49:21-50:3, 80:13-15.

44. The steam then flows from the reheater to the intermediate and low pressure portion of the turbine. The steam turns those sections of the turbine, which spin the generator that turns mechanical energy into electricity. T.T., Sept. 13, 2010, at 56:2-15.

45. After passing through the turbine for the last time, the steam is condensed to water, and returns to the boiler. T.T., Sept. 13, 2010, at 56:2-15.

46. Before the condensed water flows again into the waterwall tubes, it passes through a component known as the economizer, where it is heated by the combustion gases

before they pass through pollution controls and then the stack. T.T., Sept. 13, 2010, at 50:14-23.

47. Before entering the stack, hot combustion gases also pass through an air heater and heat the incoming air. T.T., Sept. 13, 2010, at 50:14-51:10.

48. Leaving the boiler and passing through pollution controls, if any, combustion gases are discharged to the atmosphere though a stack. T.T., Sept. 13, 2010, at 53:9-54:10.

49. Typical air contaminants produced by coal combustion include oxides of nitrogen ("NO_x"), sulfur dioxide ("SO_2") and particulate matter. T.T., Sept. 13, 2010, at 51:11-23.

50. There are numerous types of pollution controls that can be installed within a unit. For example, before combustion gases enter the atmosphere, particulate matter in the gases can be reduced by electrostatic precipitators or baghouses. T.T., Sept. 13, 2010, at 53:9-54:10.

51. SO_2 in the gases can be reduced by scrubbers, which are also called flue gas desulfurization units. T.T., Sept. 13, 2010, at 54:11-24.

52. NO_x in the combustion gases can be reduced by selective catalytic reduction (SCR) units. T.T., Sept. 13, 2010, at 55:12-56:1.

53. Another method of reducing NO_x emissions is the use of low-NO_x burners which produce fewer oxides of nitrogen when combusting coal than prior generations of burners. T.T., Sept. 13, 2010, at 47:14-48:4.

54. Continuous emission monitors (CEM) measure the amount of pollutants emitted from the stack on a continuous basis. T.T., Sept. 13, 2010, at 55:1-11.

B. Standard Measures of Power Plant Operation and Performance

55. The terms “unit rating”, “unit capability” or “unit capacity” all refer to the maximum amount of electricity, expressed in megawatt hours, that a unit can generate at full power. T.T., Sept. 20, 2010, at 10:17-11:2.

56. A megawatt hour is the equivalent of a million watts of electricity used for one hour. T.T., Sept. 21, 2010, at 18:3-7.

57. A kilowatt hour is the equivalent of one thousand watts of electricity used for one hour. T.T., Sept. 21, 2010, at 17:24-18:2.

58. “Heat rate” is a measure of the efficiency of a generating unit and is expressed as the amount of British Thermal Units (BTUs) of heat required to generate a kilowatt hour of electricity. T.T., Sept. 20, 2010, at 10:6-13.

59. A unit uses less coal to generate the same amount of electricity when its heat rate is lowered. T.T., Sept. 20, 2010, at 10:6-10:16; Sept. 21, 2010 at 24:8-25:1.

60. An electric generating unit is “available” when it is capable of producing electricity if needed. T.T. Sept. 14, 2010, at 200:20-201:5.

61. A unit is in reserve shutdown when it is available to generate electricity but that electricity is not needed. T.T., Sept. 22, 2010, at 198:23-199:6

62. A unit is “unavailable” during a planned shutdown, known as a planned outage. T.T., Sept. 14, 2010, at 200:23-25, 203:2-9.

63. Electric generating utilities schedule planned outages on a regular basis to conduct repairs of equipment. T.T., Sept. 14, 2010, at 203:6-9.

64. A unit is also “unavailable” during an unplanned shutdown, known as an unplanned or forced outage. T.T., Sept. 14, 2010, at 203:10-19.

65. A forced outage occurs when a sudden problem with the unit renders it unable to generate electricity until the problem is fixed. T.T., Sept. 14, 2010, at 203:10-19.

66. Tube leaks or failures are the most common cause of forced outages. T.T., Sept. 14, 2010, at 203:20-25.

67. A single tube leak can shut a unit down for four days. PTX 704 at AE_DUN_00005228.

68. A derating occurs when a unit can operate but not at its maximum capacity because of an equipment problem. T.T., Sept. 14, 2010, at 201:11-17.

69. A unit's availability factor is the percentage of time in a year that a unit was available to generate electricity if needed because it was not shut down for planned or forced outages. T.T., Sept. 14, 2010, at 201:18-23.

70. A unit's equivalent availability factor ("EAF") is a refinement of the availability factor that takes into account the effects of deratings and outages on a unit's availability. T.T., Sept. 14, 2010, at 201:11-202:11 ; T.T., Sept. 21, 2010, at 42:19-22 .

71. The utilization factor ("UF") of a unit is the percentage of time the unit is actually operated when it is available to operate. T.T., Sept. 21, 2010, at 42:23-43:1.

72. The capacity factor of a unit is a ratio of (i) the megawatts of electricity produced by that unit during a particular time period and (ii) the total megawatts that could have been produced by the unit during the same time period if it were operated at maximum capacity. T.T., Sept. 21, 2010, at 22:19-23:11.

73. A unit with a 70 percent capacity factor in a year has produced 70 percent of the megawatts of electricity that the unit could have produced had it operated at full power during the year. T.T., Sept. 21, 2010, at 22:19-23:8.

74. A unit is baseloaded when it is operated all or most of the time when it is available. T.T., Sept. 14, 2010, at 202:12-203:1; T.T., Sept. 23, 2010, at 136:9-136:13.

C. <u>The Generating Availability Data System</u>

75. After the 1965 blackout, the Federal Energy Regulatory Commission established the North American Electric Reliability Council ("NERC") to improve the reliability of the country's electricity generating and distribution systems. T.T., Sept. 22, 2010, at 155:14-156:16.

76. As part of that effort, NERC created the Generating Availability Data System ("GADS") to gather and make accessible data about the performance of electric generating utilities to assist them in efforts to increase unit availability. T.T., Sept. 14, 2010, at 198:4-199:9.

77. Mr. Koppe played a principal role in the creation of GADS. T.T., Sept. 14, 2010, at 198:4-199:6.

78. Ninety percent of the electric utility companies in the United States, including Allegheny, report data about their operations to GADS. T.T., Sept. 14, 2010, at 211:8-17.

79. GADS includes an "event" database that contains the following information from electric utilities, including Allegheny: (i) each time any one of a utility's generating units is not operating or is derated; (ii) the reason the unit is not operating or is derated; (iii) the beginning and end times of the outage or derate; (iv) the total hours of the outage or derate; and (v) a narrative description of the cause of the outage or derate. PTX 69 (Allegheny's GADS event data); T.T., Sept. 14, 2010, at 211:8-214:2; T.T., Sept. 23, 2010, at 19:16-20:05; DTX 1399.

80. When a unit is in a planned outage, the letters "PO" appear in the GADS event database. DTX 1399; T.T., Sept. 23, 2010, at 19:16-21:14; 23:25-24:5.

81. When a unit is in an unplanned or forced outage, the letters "U1" appear in the GADS event database. DTX 1399; T.T., Sept. 23, 2010, at 19:16-21:14.

82. When a unit is in a reserve shutdown, the letters "RS" appear in the GADS database. T.T., Sept. 23, 2010, at 28:7-28:12.

83. GADS also includes a performance database that contains information from electric utilities, including Allegheny, about the annual performance characteristics of each generating unit, including its generation, hours of availability, hours of utilization, total planned and forced outage hours, the characteristics of its fuel and the manner in which the unit was operated. PTX 70 (CD containing Allegheny GADS Data – Excel Spreadsheet – Allegheny Energy Annual Summaries).

84. When a utility reports a unit to the GADS performance database with a code number "1," it means the unit is baseloaded. GADS Data Reporting Instructions Section IV at page IV-7, *available at* www.nerc.com/files/section_4_Performance_Reporting.pdf.

85. Utilities, including Allegheny, use the GADS database to track which pieces of equipment are causing forced outages. T.T., Sept. 23, 2010, at 19:16-22:10.

D. The Utility Industry's Historical Success in Increasing the Availability and Longevity of its Generating Units

86. Large numbers of new coal fired generating units had begun operating in the late 1960s and early 1970s. T.T., Sept. 14, 2010, at 206:16-207:19.

87. These units experienced more problems than earlier vintage generating units and were available only 60 to 65 percent of the time. T.T., Sept. 14, 2010, at 206:20-207:8.

88. In 1976, the average coal fired electric generating unit was available only 250 days per year. T.T., Sept. 20, 2010, at 75:4-14.

89. The utility industry responded to declining availability by creating boiler availability improvement programs that replaced major deteriorated pieces of equipment with new and better designed equipment. T.T., Sept. 14, 2010, at 208:11-209:4.

90. By 1990, the average coal generating unit was available 300 days per year, an increase of 50 days per year. T.T., Sept. 20, 2010, at 75:15-17.

91. From 1990 to 2000, the average availability of all coal fired electric generating units increased by 9 days per year. T.T., Sept. 20, 2010, at 76:6-13.

92. The industry-wide increase in availability could not have happened without the replacement of major defective pieces of equipment with new and better designed equipment. T.T., Sept. 14, 2010, at 208:11-209:4; T.T., Sept. 20, 2010, at 75:22-76:5.

93. Beginning in the 1980s, the utility industry also embarked on an effort to extend the lives of coal fired electric generating units built in the late 1950s that were then reaching the end of their design life. T.T., Sept. 14, 2010, at 210:10-211:1.

94. This effort was known as "life extension" in the industry and involved replacing major pieces of equipment at 30 to 35 year old units to extend their lives to 50 or 60 years, or longer. T.T., Sept. 14, 2010, at 210:10-211:7; DTX 97 at .0001, 0005.

E. Allegheny Expected That Major Component Replacements Would Increase the Availability and Generation of its Generating Units

95. Allegheny pursued a number of programs throughout the years to increase unit availability through replacement of major components PTX 563**,** 720**,** 716.

96. For example, Allegheny instituted a system-wide boiler availability improvement program in the 1990s. PTX 720, 563.

97. That program led to major component replacements at Allegheny's Albright, Armstrong, Hatfield, Mitchell, Fort Martin, Harrison, and Pleasants power stations. PTX 720, 563; T.T. Sept. 20, 2010, at 90:23-92:8.

98. All of the projects at issue in this case were implemented pursuant to recommendations made under Allegheny's boiler availability improvement program. PTX 720, 563; T.T. Sept. 20, 2010, at 90:23-92:8.

99. The purpose of the completed and planned replacements at issue in this case was "to improve the power stations' availability and reliability." PTX 563.

100. As part of its availability improvement program in the 1990s, Allegheny decided to increase the time between planned outages at its generating units from one per year to one every 18 months. PTX 716 at AE_HQ_00465786.

101. Allegheny also decided to increase the time between major overhaul outages at its generating units from once every 5 years to once every 6 years for its supercritical units and to once every 7.5 years for its subcritical units. PTX 716, *passim*.

102. As Allegheny employee Paul Kramer explained, reducing planned outages causes a significant increase in a unit's availability. T.T., Sept. 22, 2010, at 197:14-198:13.

103. The new planned outage schedule was estimated to increase the unit availability of the supercritical units by 2 percent, assuming no increase or decrease in the forced outage rate. PTX 716 at AE_HQ_00465788.

104. The new planned outage schedule was estimated to increase the unit availability of the subcritical units by 1.4 percent, assuming no increase or decrease in the forced outage rate. PTX 716 at AE_HQ_00465789.

105. Elimination of a planned outage in a particular year will result in a proportional increase in the equivalent availability factor for that year. T.T., Sept. 22, 2010, at 197:14-198:13

106. As part of Allegheny's boiler availability improvement project, Allegheny established a "boiler group" to study the forced outage rate of Allegheny's units and "its impact on total unit availability." PTX 720 at AE_ARM00122562.

107. In the 1990s, the boiler group studied the effect of tube leaks in each section of Allegheny's boilers on total unit unavailability and developed a computerized database of all tube leaks in the system. PTX 720 at AE_ARM00122562-2564..

108. The boiler group recommended the purchase of software to allow maximum use of the data in order to become "even more proactive and predictive in dealing with the No. 1 industry problem contributing most to unit unavailability." PTX 720 at AE_ARM00122562-2563..

109. In order to improve boiler availability, the boiler group also anticipated conducting a system-wide review "of boiler maintenance inspection practices," and recommending specific training of station personnel to achieve the objective of reducing boiler unavailability. PTX 720 at AE_ARM00122564..

110. These efforts to improve boiler availability continued in the new millennium. For example, in the spring of 2005, Allegheny instituted a boiler inspection project to improve boiler availability by identifying for repair or replacement those components "that were adversely affecting the availability of the System boilers or could affect availability in the future . . . ." PTX 1832 at AE_HQ_00435359.

111. Allegheny projected that the boiler inspection project would eventually avoid 144 hours of forced outage time per year at all of the companies' units by repairing or replacing the components that had caused that amount of outage time. PTX 1832; D.T. (David Piktel), Sept. 29, 2009, at 98:17-100:14.

112. In a conference call with Allegheny investors on October 28, 2005, Paul Evanson, Allegheny's President and CEO, described the company-wide initiative to increase power plant availability, particularly at the company's super critical plants, by replacing major 30 year old components during extended planned outages. PTX 1837 at 2; PTX 1840 at 7.

113. Through this initiative, Allegheny hoped to increase the EAF at its super critical plants from 85 percent in 2005 to 91 percent in 2007. PTX 1837 at 2.

114. At a November 7, 2006 presentation at the Edison Electric Institute, Mr. Evanson described how the forced outage rate had gone down from 12 percent to 5 percent at four of the units in which major repair and replacement work had already been done. PTX 1842 at 3.

115. Allegheny's drive to improve availability at its supercritical plants was based on increasing generation at these units which are low cost and are usually dispatched when they are available. PTX 1842 at 2.

116. The relationship between increased availability and increased generation was made explicit by Mr. Evanson at a September 26, 2006 meeting with energy analysts, where he explained that every percentage point improvement in power plant availability is worth between 10 and 12 million dollars in additional revenue. PTX 1840 at 2.

117. In its Forms 10-K, filed with the Securities and Exchange Commission for the years 2005 and 2006, Allegheny told its shareholders that Allegheny was "working to

maximize the availability and operational efficiency of its physical assets, particularly its supercritical generation facilities." PTX 32 at 54; PTX 33 at 58.

118. In its Form 10-K, filed with the Securities and Exchange Commission for the year ending 2005, Allegheny explained to its shareholders that more fuel had been consumed in 2005 than in 2004, because of a "4.2% increase in total MWhs generated as a result of increased availability at Allegheny's coal fired plants." PTX 33 at 79.

119. In its Form 10-K, filed with the Securities and Exchange Commission for the year ending December 31, 2006, Allegheny explained to its shareholders that the increase in megawatt hours generated from the previous year was due, in part, to "increased availability of Allegheny's supercritical plants." PTX 34 at 89.

120. Indeed, Allegheny consistently communicated to its shareholders the importance of increasing unit availability in its Forms 10-K for the years1993 through 2000 which informed its shareholders that the company's operating subsidiaries would continue to study ways to meet future increases in customer demand, by, among other things, "increasing the efficiency and availability of the system's generating facilities." PTX 20 at 16 (18 pdf), PTX 21 at 13 pdf; PTX 22 at 21 (13 pdf), PTX 23 at 23 (19 pdf), PTX 24 at 20 (23 pdf), PTX 25 at 24 (22 pdf) PTX 26 at 24 (22 pdf).

121. The connection between availability and generation was also made explicit in Allegheny's Forms 10-K for the years 1993 through 1995, in which Allegheny explained to its shareholders that the amount of power it must purchase from nonaffiliated utilities depends, among other factors, upon the availability of the Company's generating equipment. PTX 20 at M-3 (47 pdf), PTX 21 at 9 pdf, PTX 22 at 61-62 (42 pdf).

122. Paul Kramer, Allegheny's 30(b)(6) witness on availability, succinctly summarized Allegheny's understanding of the relationship between increased availability and increased generation by testifying that any project that reduces a unit's forced outage rate will proportionately increase its capacity factor and its utilization factor. D.T. (Paul Kramer 30(b)(6) witness on Armstrong issues), July 26, 2007, at 137:10-138:10.

F. Allegheny Focuses on Increasing Unit Availability When It Determines <u>Whether to Replace a Major Component</u>

123. To determine whether to replace a major component that has been causing forced outages, Allegheny performed an economic analysis that compared the cost of installing a new component to the cost of operating in the future with the old component. PTX 704 at AE_DUN_00005220; D.T. (David Piktel), Sept. 29, 2009, at 92:4-92:23.

124. The cost of operating with the old component includes the projected loss of money associated with anticipated future forced outages and the cost of fixing and maintaining the component causing the forced outages. PTX 704 at AE_DUN_00005227; D.T. (David Piktel), Sept. 29, 2009, at 93:5-94:5.

125. The cost of a forced outage includes the cost of labor to repair the component, the cost of energy to replace the electric generation from the unit while it is in a forced outrage, and the cost of restarting the unit after the problem has been repaired. PTX 704 at AE_DUN_00005227-28; D.T. (David Piktel), Sept. 29, 2009, at 93:4-94:5.

126. The most significant cost of a forced outage is the cost of replacement energy. T.T., Sept. 20, 2010, at 19:16-20:8.

127. In conducting an economic analysis, Allegheny estimates the effective life of the proposed new component. PTX 704 at AE_DUN_00005227.

128. Allegheny assumes that there will be no forced outages in the future due to the new component over its effective life. PTX 704 at AE_DUN_00005227-5229.; D.T. (David Piktel), Sept. 29, 2009, at 128:11-22

129. Allegheny assumes there will be no cost of replacement energy due to the new component because it will not cause forced outages that would take the unit off-line. PTX 704 at AE_DUN_00005227-5229; T.T., Sept. 20, 2010, at 21:4-21:23.

130. The cost of the new component is the present cost of purchasing and installing the new component, and of removing the old component. PTX 704 at AE_DUN_0000529.

131. Allegheny estimates the number of future forced outages that would be caused by the old component over the life span of a new component, estimates the costs of those future forced outages over the lifespan of a new component and discounts these future costs to a present value. PTX 704 at AE_DUN_00005227 - AE_DUN_00005228.

132. The costs of future forced outages caused by the old component are then compared to the cost of replacing the old component with a new one. PTX 704 at AE_DUN_00005229.

133. The less expensive alternative is generally recommended. T.T., Sept. 23, 2010, at 151:21-152:5.

134. Allegheny assumes that the availability of a unit will always be higher in the future if a major component that has been causing outages is replaced than it would have been if the component is not replaced. T.T., Sept. 20, 2010, at 72:13-23.

135. Allegheny assumes that the unit will generate more electricity in the future if a major component that has been causing outages is replaced than it would have generated if the component is not replaced. T.T., Sept. 20, 2010, at 50:16-50:25.

136. Allegheny also assumes that once the component is replaced, the unit will run more in the future than in the past because the outages previously caused by that component will not occur, and everything else in the unit will remain the same. D.T. (David Piktel), Sept. 29, 2009, at 129:3-129:17.

III. THE ARMSTRONG, HATFIELD'S FERRY AND MITCHELL POWER STATIONS

137. This litigation concerns three coal-fired electricity generating stations operated by Allegheny: Armstrong, Hatfield's Ferry ("Hatfield") and Mitchell. Docket Item 430 ¶ 4.

138. Each of those power stations (Armstrong, Hatfield and Mitchell) is, and was at the time of the projects at issue in this case: a "major emitting facility," as term is defined in 42 U.S.C. § 7479(1), a "major stationary source," as that term is defined in 40 C.F.R. § 52.21(b)(1)(i)(b) and 25 Pa. Code § 127.83, a "major NO_x emitting facility" as that term is defined in 25 Pa. Code § 121.1, and a "major facility" for SO_2 as that term is defined in 25 Pa. Code §121.1. Docket Item 430 ¶ 5.

A. Armstrong Power Station

139. The Armstrong Power Station is located in Washington Township, Armstrong County. Docket Item 430 ¶ 7.

140. There are two coal fired boilers located at the Armstrong Power Station. Docket Item 430 ¶ 8.

141. The Armstrong units were baseloaded in the mid to late 1990s. DTX 1052 at AE_HQ_00269605.

142. Unit 1 was placed into service in 1958; Unit 2 was placed into service in 1959. Docket Item 430 ¶¶ 9, 10.

143. Unit 1 and Unit 2 are subcritical boilers. T.T., Sept. 13, 2010, at 57.

144. Unit 1 and Unit 2 each have a capacity of 170-180 MW each. T.T., Sept. 13, 2010, at 57:18-23.

145. The Armstrong Power Station is located in an area that has been classified as non-attainment with the National Ambient Air Quality Standard for sulfur dioxide ("SO_2") since 1978. Docket Item 430 ¶ 12.

146. The Armstrong Power Station is located in an area that was classified as moderate non-attainment for ozone under the 1 hour standard from 1978 to October 18, 2001. Docket Item 430 ¶ 13.

147. Since October 19, 2001 the area where the Armstrong Power Station is located has been in attainment for ozone under the 1 hour standard. Docket Item 430 ¶ 14.

148. The Armstrong Power Station is located in an area that has been classified as attainment for NO_2 since 1978. Docket Item 430 ¶ 15.

B. <u>Hatfield's Ferry Power Station</u>

149. The Hatfield's Ferry ("Hatfield") power station is located in Greene County, Pennsylvania. Docket Item 430 ¶ 16.

150. Hatfield includes three units that generate electricity, Units 1, 2 and 3, and each burns coal as its primary fuel. Docket Item 430 ¶ 17.

151. Unit 1 went into service in 1969. Docket Item 430 ¶ 18.

152. Unit 2 went into service in 1970. Docket Item 430 ¶ 19.

153. Unit 3 went into service in 1971. Docket Item 430 ¶ 20

154. Each Hatfield unit has a maximum capacity of approximately 579 megawatts. DTX 1052 at AE_HQ_00269687.

155. Each Hatfield unit is an "electric utility steam generating unit" within the meaning of 40 C.F.R. § 60.2 and 25 Pa. Code § 122.3 (as made federal law by 40 C.F.R. §§ 52.2020-2062). Docket Item 430 ¶ 21

156. Each Hatfield unit was baseloaded during the 1990s. PTX 1238 at 4 (Hatfield 1: lines 24-33, column J), at 4-5 (Hatfield 2: lines 49-58, column J), at 5 (Hatfield 3: lines 74-83, column J) (CD-GADS data); GADS Data Reporting Instructions Section IV at page IV-7, *available at* www.nerc.com/files/section_4_Performance_Reporting.pdf.; T.T., Sept..20, 2010, at 11:14-19; T.T., Sept. 23, 2010, at 136: 9-17.

157. At all times relevant to this action, Greene County, Pennsylvania, where Hatfield is located, was in attainment or unclassifiable for both SO_2 and NO_x. Docket Item 430 ¶ 22.

C. <u>Mitchell Power Station</u>

158. The Mitchell power station is located in Washington County, Pennsylvania. Docket Item 430 ¶ 61.

159. It includes three units, Units 1, 2 and 3. Docket Item 430 ¶ 62.

160. Units 1 and 2 are oil-fired while Unit 3 is coal-fired. Docket Item 430 ¶ 62.

161. Unit 3 went into service in 1963. Docket Item 430 ¶ 63.

162. Unit 3 has a net capacity of 288 megawatts. PTX 958 at AE_HQ_00376670.

163. Unit 3 is an "electric utility steam generating unit" within the meaning of 40 C.F.R. § 60.2 and 25 Pa. Code § 122.3 (as made federal law by 40 C.F.R. §§ 52.2020-.2062). Docket Item 430 ¶ 64.

164. Unit 3 was a baseloaded facility during the 1990s. DTX 1052 atAE_HQ_00269726; PTX 70 (CD containing Allegheny GADS Data – Excel Spreadsheet –

Allegheny Energy Annual Summaries); GADS Data Reporting Instructions Section IV at page IV-7, available at www.NERC.com/files/GADS_DRI_Complete_Version_010111.pdf .

165. The Mitchell power plant is located in an area that has been in attainment for NO_2 from 1978 to the present. Docket Item 430 ¶ 65.

IV. THE ARMSTRONG RECONSTRUCTION PROJECTS

166. Reconstructed emission units are existing units to which such extensive changes have been made that they are treated like new units. T.T, Sept. 13, 2010, at 60:19-22, 169:24-170:3.

167. The first step to show that an emission unit is reconstructed under federal and Pennsylvania NSPS regulations is determining if the fixed capital costs of the new components are at least 50 percent of the fixed capital cost of an entirely new comparable emission unit. T.T, Sept. 13, 2010, at 61:8-12, 61:21-62:11, 62:20-24.

168. Fixed capital cost means the cost of the capital needed to provide all of the depreciable components. 40 C.F.R. § 60.15(c).

169. For reconstruction purposes, a coal fired power plant boiler emission unit ("boiler") is understood to include all components between the "coal bunkers" to the "stack breeching." T.T., Sept. 13, 2010, at 65:17-68:1; PTX 137 at 2 & Attachment C.

A. The Background and Purpose of the Armstrong Reconstruction Projects

170. In 1987, Allegheny hired Foster Wheeler Energy Company ("Foster Wheeler"), a power plant engineering company, to evaluate the condition of the Armstrong 1 boiler. PTX 247 at AE_DUN_00614495.

171. In 1988, Foster Wheeler produced a fitness assessment that documented the condition of the unit 1 boiler. PTX 247.

172. The objectives of Foster Wheeler's boiler fitness assessment were (a) to evaluate the condition of the steam generating components, (b) to recommend methods to maintain or improve the levels of availability and reliability, and (c) to enable Allegheny to plan for the continued service of Armstrong 1. PTX 247 at AE_DUN_00614495.

173. Foster Wheeler's assessment report found that many boiler components at Armstrong 1 were in need of repair, redesign or replacement. PTX 247 at AE_DUN_00614498-4500 *passim*.

174. Foster Wheeler did not address reducing NO_x emissions in the 1998 fitness assessment. PTX 247,

175. In 1988 when the fitness assessment was completed, the condition of Armstrong 2 was similar to the condition of Armstrong 1. D.T. (Clark Colby 30(b)(6) witness on Armstrong 2), June 28, 2007, at 25:10-26:18.

176. In 1991, Allegheny's technical staff recommended to management undertaking a complete rehabilitation of the Armstrong 1 boiler (the "Reconstruction Project") at an estimated cost of over $31,000,000. T.T., Sept. 13, 2010, at 76:16-77:9; PTX 828 at R-3 22637-2638..

177. The purposes of the Armstrong 1 Reconstruction Project were to reduce maintenance costs, to reduce the number of and cost of start-ups, to improve the availability of the boilers, to improve boiler efficiency, to reduce the amount of unburned carbon and to reduce NO_x emissions. PTX 828 at R-3 22644; D.T. (Clark Colby 30(b)(6) witness on Armstrong 1), June 22, 2007, at 73:1-11.

178. Allegheny also decided to undertake a similar Reconstruction Project for Armstrong 2. D.T. (Clark Colby 30(b)(6) witness on Armstrong 2) June 28, 2007, at 37:7-39:17.

179. The purposes of the Armstrong 2 Reconstruction Project were the same: to reduce maintenance costs, to reduce the number of and cost of start-ups, to improve the availability of the boilers, to improve boiler efficiency, to reduce the amount of unburned carbon and to reduce NO_x emissions. D.T. (Clark Colby 30(b)(6) witness on Armstrong 2), June 28, 2007, at 37:24-39:17.

B. <u>The Scope of the Armstrong Reconstruction Projects</u>

180. The Armstrong 2 Reconstruction Project was performed during a major outage in 1994. T.T., Sept. 13, 2010, at 77:10-14.

181. Allegheny completed the Armstrong 2 Reconstruction Project during a 1996 outage by performing some additional work. T.T., Sept. 13, 2010, at 77:10-14.

182. The work performed on unit 2 in 1994 and 1996 was part of a single project, the Armstrong 2 total boiler rehabilitation. T.T., Sept. 13, 2010, at 77:15-22.

183. The unit 1 total boiler rehabilitation work was performed during a seven month major outage in 1995. T.T., Sept. 13, 2010, at 77:10-11; PTX 356 at R-3 22824.

184. The following components were replaced in the Armstrong 1 Reconstruction Project:

(a) new components and reinforcement of boiler structure

(b) new draft plant components (e.g., new air preheaters, new forced draft fans, among other things);

(c) new superheater area;

(d) new reheater area;

(e) new economizer;

(f) new boiler water wall tubes;

(g) new wind box;

(h) new burners, burner management system, and coal pipes;

(i) new penthouse;

(j) new vestibule;

(k) new ash hopper;

(l) new boundary and curtain air system;

(m) new over-fire air system;

(n) new soot blowers;

(o) new spray water systems;

(p) new boiler safety valves;

(q) new boiler controls; and

(r) new damper drives for the induced draft fans and forced draft fans.

T.T., Sept. 13, 2010, at 79:3-84:3; PTX 356 at R-3 22824 - 2831.

185. When the 1995 Armstrong 1 Reconstruction Project was completed, the only components that had not been replaced were the steam drum, the downcomer feeder tubes, six downcomers, the pulverizers, and some portion of the foundation. T.T., Sept. 13, 2010, at 84:12-18; PTX 356 at R-3 22824 - 2825.

186. Allegheny replaced the same components in the Armstrong 2 Reconstruction Project as it did in the Armstrong 1 Reconstruction Project. T.T., Sept. 13, 2010, at 84:4-11; D.T. (Clark Colby 30(b)(6) witness on Armstrong 2), June 28, 2007, at 67:16-71:4, 76:20-80:15.

187. In addition, during the Armstrong 2 Reconstruction Project, Allegheny replaced some of the downcomer tubes. T.T., Sept. 13, 2010, at 84:4-11.

188. When the Armstrong 2 Reconstruction Project was completed, the only components that had not been replaced were the steam drum, some of the downcomer tubes, some of the downcomers , the pulverizers, and some portion of the foundation. T.T., Sept. 13, 2010, at 84:4-11; D.T. (Clark Colby 30(b)(6) witness on Armstrong 2), June 28, 2007, at 32:20-33:16, 68:2-7.

189. Allegheny changed the boiler support systems in the Armstrong Reconstruction Projects. T.T., Sept. 13, 2010, at 79:12-20.

C. <u>The Reconstruction Projects Constituted a Reconstruction of the Boilers</u>

190. The NSPS "reconstruction" requirements are triggered if the costs associated with replacement of the boiler-related components at issue represent at least 50 percent of the costs associated with constructing a comparable entirely new boiler. T.T., Sept. 13, 2010 at 60:25-62:11**.**

191. Thus, two different types of cost data are needed to make a "reconstruction" determination: (i) costs associated with the actual replacement of the boiler-related components at issue; and (ii) costs associated with constructing a comparable entirely new boiler. T.T., Sept. 13, 2010, at 60:25-62:11.

1. The Costs of the Armstrong Reconstruction Projects

192. The cost of the Armstrong 1 Reconstruction Project was $52,431,805. PTX 908. .

193. The cost of the Armstrong 2 Reconstruction Project was $53,302,358. T.T., Sept. 13, 2010, at 184:17-18; T.T., Sept. 28, 2010, at 83:6-11; PTX 908.

2. Comparing the Costs of the Armstrong Reconstruction Projects to the Costs of Comparable Entirely New Boilers

194. Plaintiffs' established the cost of a comparable new boiler using three separate methodologies. T.T., Sept. 13, 2010, at 74:13-77:9, 122:22-124:14, 129:3-20, 184:19-185:11, 189:13-191:4, PTX 904, PTX 906; PTX 908.

195. Two witnesses, Ranajit Sahu and Hugh Larkin, were accepted by the Court as experts, and explained these methodologies and their results.

196. Ranajit Sahu has a bachelor's degree, a master's degree and a Ph.D. in mechanical engineering, took many courses in power plant design, operation and construction and specialized in coal combustion and the creation and control of pollutants from that process. T.T., Sept. 13, 2010, at 4-10, 35:20-36:3, 37:1-8.

197. After his graduate studies, Dr. Sahu worked in industry, designing large boilers, and in the environmental consulting practice of an architectural engineering firm, and as a private consultant; estimating the costs of power plant projects was an inherent part of Dr. Sahu's consulting work. *Id.* at 36:17-25.

198. Hugh Larkin is a senior partner at Larkin & Associates, a certified public accounting firm specializing in consulting services for public service commissions, consumer groups and attorneys general, and has been a certified public accountant since 1966. T.T., Sept. 13, 2010, at 173:20-175:24.

199. Mr. Larkin has testified as an expert in approximately 350 proceedings before public service commissions in which utilities are requesting rate increases and has reviewed utility financial records and their underlying documentation in order to reach conclusions about a utility's revenue requirements. *Id.* at 176:10-177:11.

200. Under each methodology used by Dr. Sahu and Mr. Larkin, the cost of the Armstrong Reconstruction Projects exceeded 50 percent of the cost of a comparable new boiler. *See* Plaintiffs' Findings of Fact 201-234 below.

a. Plaintiffs' Method 1: Original Cost Basis

201. An entirely new comparable boiler to Armstrong 1 and 2 boilers would be a new boiler with components that are identical, or as similar as possible, to those that are being replaced. T.T., Sept. 13, 2010, at 72:1-11, 73:16-22, 74:7-12.

202. An entirely new comparable boiler to the Armstrong 1 and 2 boilers would be comparable in function, size and design to the then-existing boilers. T.T., Sept. 13, 2010, at 133:13-19, 134:12-24, 135:2:-136:10.

203. The rebuilt Armstrong boilers are comparable to the boilers before they were reconstructed. T.T., Sept. 13, 2010, at 74:24-22, 129:7-20.

204. The best approach to determine the cost of a comparable entirely new facility to the Armstrong boilers is to use the then-existing Armstrong boilers as comparable units because this approach requires the fewest assumptions, and original costs for the Armstrong boilers are known. T.T., Sept. 13, 2010, at 74:24-76:7, 128:24-129:20.

205. Original cost basis ("original cost") means the initial cost of an emission unit adjusted for components removed and components added. T.T., Sept. 13, 2010, at 184:19-185:5; DTX 134 at 4.

206. Reliable original cost information for Armstrong 1 and 2, was compiled by Allegheny, and was used by Plaintiff States. T.T., Sept. 13, 2010, at 184:19-186:15; PTX 899.

207. Using costs of Armstrong 1 and 2 will provide the most reliable costs of an entirely new comparable boiler. T.T., Sept. 13, 2010, at 129:7-12.

208. Using the original cost basis is consistent with EPA guidance and the purposes of NSPS. T.T., Sept. 13, 2010, at 168:21-170:7, 199:23-200:9; DTX 134 at 4.

209. The original costs for the Armstrong 1 and 2 boilers are:

Unit 1: $ 50, 921,213; and

Unit 2: $ 34,819,598.

T.T., Sept. 13, 2010, at 189:2-8; PTX 904, PTX 906.

210. The cost of the Armstrong 1 Reconstruction Project exceeds 50 percent of the original cost of Armstrong 1 by $27,320, 211. T.T., Sept. 13, 2010, at 189:9-12; PTX 906.

211. The cost of the Armstrong 2 Reconstruction Project exceeds 50 percent of the original cost of Armstrong 2 by $35,892,559. T.T., Sept. 13, 2010, at 189:9-12; PTX 906.

212. The original cost for the boiler components that were not replaced by the Armstrong Reconstruction Projects – the steam drum, downcomer feedwater tubes and downcomers – is $41,912, which is trivial compared to the original cost of the boilers. D.T. (Dennis Herron), Aug. 15, 2007, at 239:10-242:22.

b. Plaintiffs' Method 2: Updated Original Cost Basis

213. Original costs for the Armstrong 1 and 2 boilers can be updated to 1994 and 1995 dollars, the time when the Armstrong Reconstruction Projects occurred, by using the Handy-Whitman Index ("Handy-Whitman" or "Index"). T.T., Sept. 13, 2010, at 189:13-191:4.

214. Handy-Whitman is widely accepted and used in the utility industry, and other industries, to translate costs of equipment over time. T.T., Sept. 13, 2010, at 120:11-12, 191:5-14; PTX 921 at iii-iv.

215. Handy-Whitman is used by and accepted by utility companies, regulators, insurance companies and others. T.T., Sept. 13, 2010, at 118:24-119:4, 119:25-120:6, 191:5-192:24, 193:14-195:2; PTX 921 at iii-iv.

216. The Index is updated annually using cost information from published sources as well as surveys of vendors, suppliers and manufacturers. PTX 921 at iii.

217. Handy-Whitman accounts for different costs in different regions of the country and breaks down costs to the level of individual FERC utility accounts. T.T, Sept. 13, 2010, at 120:7-10; PTX 921 at iv, PTX 922.

218. Allegheny has used Hardy-Whitman to translate the costs of boiler components over periods up to 42 years, which is longer than the time between construction of the Armstrong boilers and the Armstrong Reconstruction Projects. T.T., Sept. 13, 2010, at 191:22-195:2; PTX 1881 at AE_DUN_00286638, PTX 1883, PTX 1884.

219. The original cost of the Armstrong 1 boiler updated to 1995 dollars is $85,861,497. T.T., Sept. 13, 2010, at 197:1-198:12; PTX 908, PTX 915 – PTX 917.

220. The original cost of theArmstrong 2 boiler updated to 1994 dollars is

221. $74,044,895. T.T., Sept. 13, 2010, at 197:1-198:12; PTX 908, PTX 918 – PTX 920.

222. The cost of the Armstrong 1 Reconstruction Project exceeds 50 percent of the updated original cost of Armstrong 1 by $9,501,000. T.T., Sept. 13, 2010, at 189:9-12,197:20 -198:12; PTX 908.

223. The cost of the Unit 2 Reconstruction Project exceeds 50 percent of the updated original cost of Armstrong Unit 2 by $16,279,910. T.T., Sept. 13, 2010, at 189:9-12, 197:20-198:12; PTX 908.

c. Plaintiffs' Method 3: Cost Estimated Using Detailed Department of Energy Cost Information

224. Another acceptable approach for calculating the cost of a comparable new boiler involves using cost information for a "model" subcritical boiler in Section 3 and Appendix E of a Department of Energy Report, entitled "Market Based Advanced Coal Power Systems" ("DOE Report"). T.T., Sept. 13, 2010, at 122:20-124:7.

225. The DOE Report's model plant is similar to the Armstrong units in many respects. T.T, Sept. 13, 2010, at 158:16-25; PTX 144, Table 3.1-5 at page 3.1-34.

226. Section 3 and Appendix E of the DOE Report contain extensive information for a new 397.5 MW subcritical coal fired power plant, and detailed breakdowns of cost in 1998 dollars. T.T., Sept. 13, 2010, at 123:3-13, PTX 144, at 3.1-2 – 3.1-32, Appendix E.

227. Because Appendix E of the DOE Report contains a detailed breakdown of the plant's costs, the uncertainty about how to apportion costs between the boiler and the balance of the power plant is reduced. T.T., Sept. 13, 2010, at 123:3-16.

228. Plaintiffs' expert, Dr. Sahu, included all the costs for subcategories that were related at least, in part, to the boiler, even though some costs in those subcategories might have not been attributable to the boiler, because he had no rational basis to apportion them. T.T., Sept. 13, 2010, at 123:14–124:7, 124:15-125:10; PTX 129.

229. Because the DOE Report costs were for a 397.5 MW boiler, the costs were adjusted to the size of the Armstrong boilers (approximately 176 MW). T.T, Sept. 13, 2010, at 125:11-14; PTX 129.

230. Because cost information in Appendix E is expressed 1998 dollars, Handy-Whitman was used to translate costs to 1994 and 1995 dollars, when the Armstrong 2 and 1 Reconstruction Projects were done. T.T, Sept. 13, 2010, at 125:11-19; PTX 129.

231. Based upon cost information for the model plant in Appendix E of the DOE Report, the estimated cost to construct a comparable new boiler to the Armstrong Units is $491.6 per kilowatt. T.T., Sept. 13, 2010, at 125:12-19; PTX 129.

232. The costs of the Armstrong Reconstruction Projects expressed in dollars per kilowatt are: Unit 1: $271/KW; Unit 2: $266/KW. PTX 129.

233. The cost per kilowatt of the Armstrong 1 Reconstruction Project exceeded 50 percent of the cost per kilowatt of constructing an entirely new boiler by approximately $6.7 million.[1] T.T., Sept. 13, 2010, at 125:11–19; PTX 129.

234. The cost per kilowatt of the Armstrong 2 Reconstruction Project exceeded 50 percent of the cost per kilowatt of constructing an entirely new boiler by approximately $7.0 million.[2] T.T., Sept. 13, 2010, at 125:18–19; PTX 129.

3. Allegheny's Post-Hoc Approach to Determining the Cost of a Comparable New Boiler

235. Allegheny's expert Mr. Golden did not use the detailed cost information in Appendix E of the DOE report in any of his calculations of the cost of a new boiler for the Armstrong Units. T.T, Sept. 13, 2010, at 125:20-24.

236. Instead, Mr. Golden tried to determine the cost of a comparable entirely new boiler for the Armstrong units using the Electric Power Research Institute's ("EPRI") Technical Assistance Guide ("TAG") despite the fact that the TAG itself warns against applying its data to a site-specific facility. T.T., Sept. 13, 2010, at 100:15-22; PTX 145 at AE_DUN_00168541; DTX 1762.

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[1] Unit 1: (271 - (466/2)) $/kW x (176 MW) x 1,000 = $ 6.7 million. (Based on PTX 129)

[2] Unit 2: (266 - (452/2)) $/kW x (176 MW) x 1,000 = $ 7.0 million. (Based on PTX 129).

237. For example, in its initial pages, the EPRI TAG states that the cases used in the TAG "do not have the depth in design and cost estimate details required by the site-specific cases, and hence, *the comparison between a site-specific case and a TAG case is not appropriate*. T.T., Sept. 13, 2010, at 125:25-126:25; PTX 145 at AE_DUN_00168541 (emphasis added).

238. Similarly, the TAG section containing generating unit cost estimates contains a similar caveat that "*the estimates are not intended to apply to specific utilities at specific sites*, since site conditions and utility-specific conditions dictate design and cost variations" T.T., Sept. 13, 2010, at 110:19-112:3; PTX 145 at AE_DUN_00168645 (emphasis added).

239. As an example of the lack of specificity, the TAG provides cost information for broad categories such as "balance of plant," "general facilities and engineering fee" and "process and project contingency fee," with either no or only a very limited description of what is included in them. T.T., Sept. 13, 2010, at 109:7-112:11; PTX 145 at AE_DUN_00168645-00168646, 00168651.

240. The "general facilities and engineering fee" is broadly described as the "total construction cost of the general facilities, including roads, office buildings, shops, laboratories, etc." PTX 145 at AE_DUN_00168645.

241. The TAG provides insufficient information to allocate costs such as "general facilities and engineering fee" between the boiler and the rest of the power plant. T.T., Sept. 13, 2010, at 111:5-111:25.

242. Mr. Golden nevertheless allocated some of the "general facilities and engineering fee" to the boiler by assuming that a certain percentage of these costs related to the boiler. T.T., Sept. 28, 2010, at 89:3-90:9.

243. Mr. Golden's apportioning of the "general facilities and engineering fee" results in a percentage of the costs of roads and office buildings being allocated to the boiler, thus inflating the cost of a new boiler. T.T., Sept. 28, 2010, at 142:1-142:15.

244. The TAG provides no explanation of the costs that are included in the broad category "balance of plant." T.T., Sept. 13, 2010, at 110:25-111:4.

245. Mr. Golden nevertheless apportioned a percentage of the costs in the "balance of plant" category to the boiler without any idea if that allocation is appropriate. T.T. Sept. 13, 2010), at 107:24-109:6.

246. Section 3 and Appendix E of the DOE Report contains substantially more detailed and specific boiler and cost information than the TAG. T.T., Sept. 13, 2010, at 124:8-14; *compare* PTX 144 at Section 3, pages 3.1-34 (DOE Report) with PTX 145 at Section 5 (TAG).

4. Allegheny's Contemporaneous Conclusion That the Armstrong Projects Were Not Reconstructions

247. In a July 6, 1993 memorandum, Allegheny engineer Jeffrey Mooney concluded that the Armstrong Reconstruction Projects did not meet the requirements for reconstruction under the federal NSPS regulations. PTX 256 at AE_ARM00132855.

248. Mr. Mooney was a plant engineer with only a few years work experience and no experience in environmental compliance. T.T., Sept. 23, 2010, at 209:16-210:10.

249. Mr. Mooney based his analysis on the total cost of a new 360 MW coal fired power plant, not the total cost of a new boiler, as required by federal and Pennsylvania regulations. T.T., Sept. 13, 2010, at 87:11-88:2; PTX 256 at AE_ARM00132855.

250. Mr. Mooney's reconstruction analysis is incorrect because it inflated the cost of a comparable new facility by using the cost of a new power plant, and not the cost of a new boiler. T.T., Sept. 13, 2010, at 87:11-23.

251. Mr. Mooney acknowledged that he should have used the lower cost of a comparable new boiler in the denominator in his reconstruction analysis, not the higher cost of an entirely new power plant. . D.T. (Jeffrey Mooney), Aug. 22, 2007, at 178:11-179:3.

252. Mr. Mooney concluded that the reconstruction analysis for the Armstrong 1 and 2 Reconstruction Projects should have been performed by someone in Allegheny's environmental section. D.T. (Jeffrey Mooney), Aug. 22, 2007, at 151:20-24.

D. Compliance with the NSPS Emissions Limits at Armstrong 1 and 2 Is Feasible

253. Allegheny has not presented any evidence showing that it is technologically infeasible to comply with the SO_2 limit in NSPS Subpart Da. T.T., Sept. 13, 2010, at 92:23-93:1.

254. Allegheny could comply with the NSPS SO_2 emission limits at Armstrong 1 and 2 by installing scrubbers or by using low sulfur coal. T.T., Sept. 13, 2010, at 93:19-24.

255. Engineering reports prepared at Allegheny's request and direction evaluated several technologically feasible options for installing scrubbers to control SO_2 at Armstrong 1 and 2. T.T., Sept. 13, 2010, at 94:23-95:8, 96:2-4, 96:23-97:10; PTX 119 at AE_HQ_00286812 6816; PTX 125 AE_HQ_00268942-948.

256. There are no technological or logistical barriers to installing scrubbers to control emissions from Armstrong 1 and 2. T.T., Sept. 13, 2010, at 94:3-8.

257. There is no evidence that Allegheny undertook a study of the economic feasibility of complying with the sulfur dioxide limit in NSPS Subpart Da at Armstrong 1 and 2 before undertaking the Armstrong Reconstruction Projects. D.T. (Clark Colby 30(b)(6) witness on Armstrong 2), June 28, 2010, at 107:15-25, 108:23-25.

258. When it promulgated NSPS Subpart Da, EPA determined that reasonable costs of control for sulfur dioxide for the chosen emission rates ranged between $1,036 and $1,063 per ton of SO_2 removed.

259. EPA has used $3,000/ton of SO_2 removed as a reasonable cost of removal for SO_2. PTX 2159 at 3 (EPA October 1994 applicability determination).

260. A study performed by Washington Group International, Inc., for Allegheny in 2001 concluded that scrubbers could control the emission of SO_2 from Armstrong 1 and 2 for a cost of as little as $700/ton of SO_2 removed. PTX 125, Table S-2 at AE_HQ_00268943.

261. In 1980, Allegheny installed a scrubber on Unit 3 of the Mitchell Power Station, a subcritical coal fired plant of similar age to Armstrong 1 and 2. T.T., Sept. 13, 2010, at 56:16-57:2, 94:10-14; DTX 1052 at AE_HQ_00269725.

262. Since installing the scrubber some 30 years ago, Allegheny has successfully operated Mitchell 3 with the scrubber to generate electricity, easily meeting the NSPS Subpart Da SO_2 limit with emissions typically in the range of 0.1 – 0.12 lb./MM BTU. T.T., Sept. 13, 2010, at 94:15-22.

E. Since Completion of the Reconstruction Projects, Armstrong 1 and 2 Have Not Operated in Compliance with NSPS SO_2 Emissions Limits

263. At all relevant times since the completion of the 1995 Armstrong 1 Reconstruction Project, SO_2 emissions from unit 1 have exceeded the NSPS limit of 1.2 lb./MM BTU set forth in 40 C.F.R. § 60.43Da. Docket Item 431 ¶ 1.

264. At all relevant times since the completion of the 1994 Armstrong 2 Reconstruction Project, SO_2 emissions from unit 2 have exceeded the NSPS limit of 1.2 lb./MM BTU set forth in 40 C.F.R. § 60.43Da. Docket Item 431 ¶ 2.

265. Since Allegheny completed the Reconstruction Projects, SO_2 emissions at Armstrong 1 and 2 have typically exceeded 1.2 lb./MM BTU by 200 to 250 percent. T.T., Sept. 13, 2010, at 90:27-91:5; PTX 127.

266. Allegheny did not submit a permit application to PA DEP informing it of all of the activities included in the Armstrong 1 and 2 Reconstruction Projects, and seeking approval to undertake the projects. PTX 2 at ¶¶ 180, 242.

V. ADDITIONAL FACTS RELEVANT TO THE BAT CLAIMS

267. The projects relevant to PA DEP's BAT plan approval claims are the Armstrong 1 and 2 Reconstruction Projects, because they constitute "new sources" under Pennsylvania law. T.T., Sept. 13, 2010, at 62:13-65:1.

268. Allegheny did not submit an application to PA DEP for a preconstruction plan approval for the entirety of the Armstrong 1 Reconstruction Project. PTX 2 ¶ 189.

269. Allegheny did not operate Armstrong 1 subject to BAT emissions limitations after completion of the Armstrong 1 Reconstruction Project. PTX 2 ¶ 190.

270. Allegheny did not submit an application to PA DEP for a preconstruction plan approval for the entirety of the Armstrong 2 Reconstruction Project. PTX 2 ¶ 252.

271. Allegheny did not operate Armstrong 2 subject to BAT emissions limitations after completion of the Armstrong 2 Reconstruction Project. PTX 2 ¶ 253.

VI. THE PSD PROJECTS

A. The Basic Facts About Each PSD Project

1. The Armstrong PSD Projects

272. For each of the boiler rehabilitations at Armstrong, Allegheny divided the work into two separate projects and used two separate work orders to authorize the projects. T.T.,

Sept. 20, 2010, at 69:6-69:16; PTX 1318 (unit 1); PTX 1317 (unit 1); PTX 206 (unit 2); PTX 205 (unit 2).

273. At each unit, Allegheny designated a portion of the work as the "low-NO_x burner project," which included the replacement of the existing burners and certain burner related equipment at the relevant unit, but also included the replacement and upgrading of the primary furnace, radiant superheater, boiler casing, and boiler insulation system. PTX 1317 (unit 1), PTX 205 (unit 2).

274. At each unit, Allegheny designated the remaining work as the "Boiler Project," which included the replacement of the superheater, reheater, economizer, air heaters, ductwork, and sootblowers at the relevant unit. PTX 1318 at R-3 09513 (unit 1); PTX 206 at R-3 09953 (unit 2).

275. Allegheny would have had to replace the components included in the Armstrong PSD Projects whether or not it also had to install low-NO_x burners. PTX 683 at AE_DUN_00115388 - 5398.

276. The purpose of the Armstrong PSD Projects was to improve boiler performance, reduce forced outages, and increase availability at both Armstrong units. PTX 1318 at R-3 09513 (unit 1); PTX 206 at R-3 09953 (unit 2); T.T., Sept. 23, 2010, at 192:11-192:22.

277. Allegheny expected that the replacement of the primary furnace, approved as part of the low-NO_x burner project, would increase the efficiency of the Armstrong units. PTX 96 at AE_HQ_00429779.

278. Although increased efficiency at a unit may result in the unit burning less coal per kilowatt hour of electricity produced, it also typically results in increased use of the unit on an annual basis. T.T., Sept. 20, 2010, at 103:23-104:12.

279. The majority of the expected efficiency increase did not relate to the replacement of the major components done under the Boiler Project work orders, that is, not as a result of the PSD Projects. T.T., Sept. 20, 2010, at 110:7-23.

a. Unit 1 Specific Facts

280. The Armstrong 1 PSD Project was completed during a planned outage that ran from February 27, 1995 through October 23, 1995. PTX 69 at 18.

281. The final cost of the Armstrong 1 PSD Project was $28,657,739. PTX 898.

282. Allegheny indicated that one of the purposes of the work at Armstrong 1 that was undertaken in the extended 1995 outage was to remedy “the increased unavailability rate.” PTX 178 at AE_ARM00132601.

283. Based on its own analyses, Allegheny reasonably should have expected an availability increase of at least 201.5 hours/year from the Armstrong 1 PSD Project. PTX 178 at AE_ARM00132601 (calculated by taking Allegheny’s estimated annual availability increase of 4.6 percent (0.046) from all of the work done in the outage, multiplying that by 8,760 hours in a year to obtain an expected availability gain of 403 hours/year, and dividing that figure in half as a rough, “ballpark” allocation of the availability gains between the PSD Project and the remainder of the work done during the outage).

284. In the calendar year 1994 preceding the Armstrong 1 PSD Project, Armstrong 1 had an hourly SO_2 emissions rate, conservatively calculated, of 2.19 tons. PTX 1309-3 (this number represents a calculation by plaintiffs dividing annual emissions, 19,155 tons, by total number of hours in a year, 8,760).

285. In the calendar year 1994 preceding the Armstrong 1 PSD Project, Armstrong 1 emitted, on average, 40 tons of SO_2 when it operated for 18.3 hours. PTX 1309-3 (this number

represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 2.19 tons calculated in the preceding proposed finding of fact).

286. In the calendar year 1994 preceding the Armstrong 1 PSD Project, Armstrong 1 had an hourly NO_x emissions rate, conservatively calculated, of 0.724 tons. PTX 1309-3 (this number represents a calculation by plaintiffs dividing annual emissions, 6,346 tons, by total number of hours in a year, 8,760).

287. In the calendar year 1994 preceding the Armstrong 1 PSD Project, Armstrong 1 emitted, on average, 40 tons of NO_x when it operated for 55.2 hours. PTX 1309-3 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 0.724 tons calculated in the preceding proposed finding of fact).

b. Unit 2 Specific Facts

288. The Armstrong 2 PSD Project was completed during a planned outage that ran from April 26, 1994 through December 21, 1994. PTX 69 at 42.

289. The final cost of the Armstrong 2 PSD Project was $29,912,514. PTX 898.

290. Allegheny indicated that one of the purposes of the project was “to improve the overall reliability and availability of the boiler.” PTX 850 at 1.

291. Based on its own analyses, Allegheny reasonably should have expected an availability increase of at least 201.5 hours/year from the Armstrong 2 PSD Project. PTX 178 at AE_ARM00132601 (calculated by taking Allegheny’s estimated annual availability increase of 4.6 percent (0.046) from all of the work done in the outage, multiplying that by 8,760 hours in a year to obtain an expected availability gain of 403 hours/year, and dividing that figure in half as a rough, “ballpark” allocation of the availability gains between the PSD Project and the remainder of the work done during the outage).

292. In the calendar year 1993 preceding the Armstrong 2 PSD Project, Armstrong 2 had an hourly SO_2 emissions rate, conservatively calculated, of 1.87 tons. PTX 1309-2 (this number represents a calculation by plaintiffs dividing annual emissions, 16,366 tons, by total number of hours in a year, 8,760).

293. In the calendar year 1993 preceding the Armstrong 2 PSD Project, Armstrong 2 emitted, on average, 40 tons of SO_2 when it operated for 21.4 hours. PTX 1309-2 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 1.87 tons calculated in the preceding proposed finding of fact).

294. In the calendar year 1993 preceding the Armstrong 2 PSD Project, Armstrong 2 had an hourly NO_x emissions rate, conservatively calculated, of 0.530 tons. PTX 1309-2 (this number represents a calculation by plaintiffs dividing annual emissions, 4,644 tons, by total number of hours in a year, 8,760).

295. In the calendar year 1993 preceding the Armstrong 2 PSD Project, Armstrong 2 emitted, on average, 40 tons of NO_x when it operated for 75.4 hours. PTX 1309-2 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 0.530 tons calculated in the preceding proposed finding of fact).

2. The Hatfield's Ferry Lower Slope PSD Projects

296. Allegheny began planning to replace the lower slopes, inlet headers, seal skirts and ash hoppers (the "lower slope projects") at all three Hatfield units in early 1995. PTX 704.

297. The purpose of the lower slope projects was to "increase the availability and reduce future maintenance and operating costs" of the Hatfield power station. PTX 704 at AE_DUN_00005220.

298. The lower slope projects would not affect either the capacity or the efficiency of the Hatfield units. T.T., Sept. 20, 2010, at 39:13-22, 51:1-7.

299. The failures in the lower slopes in the Hatfield units had caused 31 forced outages totaling 2,750 hours since January 1992. PTX 704 at AE_DUN_00005218.

300. Lower slope outages had reduced unit availability at the Hatfield units by an average of 3.5 percent and as high as 7 percent since January 1992. PTX 704 at AE_DUN_00005219.

301. During the first five months of 1995, lower slope tube failures at all three units had caused 700 hours of forced outage time. PTX 704 at AE_DUN_00005219.

302. Lower slope tube failures at all three units cause 8 forced outages per year and each forced outage averaged 4 days of down time. PTX 704 at AE_DUN_00005227.

303. Allegheny predicted that the Hatfield power station would experience eight 4-day forced outages per year in the next 25 years due to problems with lower slope tube leaks if the projects were not done. PTX 704 at AE_DUN_00005228.

304. Allegheny assumed that there would be no forced outages caused by the lower slope tubes for 25 years into the future if the projects were done. PTX 704 at AE_DUN_00005227; T.T., Sept. 20, 2010, at 39:13-14, 43:09-44:7, 50:16-20.

305. Allegheny estimated that it would spend $28,516, 863 on replacement energy for the three Hatfield units during the next 25 years if the projects were not done. PTX 704 at AE_DUN_00005228.

306. Allegheny assumed that there would no cost of replacement energy for the 3 Hatfield units during the next 25 years if the projects were done. PTX 704 at AE_DUN_00005229.

307. Allegheny described the Hatfield Power Station lower slope project as "very aggressive" with "the potential of decreasing our forced outage rate and increasing our availability." PTX 707.

308. The slope tube panels in each unit are large, about 60 feet wide. Docket Item 166 ¶ 27.

309. Each new slope panel included 464 tubes, and the slope panels were just one part of the projects. *See* PTX 187 at AE_DUN_00131869 - 876.

310. Allegheny assumed that the Hatfield units would generate electricity for at least an additional 768 hours per year after the lower slope projects because the units would not be shut down each year for 8 four-day outages as it had been before the projects. PTX 704 at AE_DUN_00005228; T.T., Sept. 20, 2010, at 50:21-25.

a. Unit 1 Specific Facts

311. The purpose of the Hatfield 1 lower slope replacement project was to "improve the availability and reliability of the boiler." PTX 216 at AE_HQ_00173847; D.T. (Clark Colby 30(b)(6) witness on the Hatfield's Ferry projects), July 27, 2007, at 49:9-49:23, 57:17-58:16.

312. Allegheny began planning the Hatfield Unit 1 lower slope project in 1995, more than two years before performing it. Docket Item 430 ¶ 26.

313. Allegheny performed the project in the fall of 1997, during a planned outage that ran from October 11, 1997 through December 20, 1997. Docket Item 430 ¶ 27.

314. The project involved completely replacing the lower slope tubes, seal skirt and ash hopper, in a manner that allowed for design improvements such as thicker tubes and

redesigned materials and configuration of the furnace seals to improve their longevity. Docket Item 430 ¶ 28.

315. The work was performed by outside contractors using materials fabricated by outside contractors. Docket Item 430 ¶ 29.

316. The complete replacement of the lower slope tube panels was necessary because repeated attempts at partial replacements continued to fail. Docket Item 430 ¶ 30.

317. The project cost $5,918,077. Docket Item 430 ¶ 31.

318. Allegheny treated the project as a capital expenditure, not a maintenance expense, for accounting purposes. Docket Item 430 ¶ 32.

319. A project at an electric generating unit is classified as a “capital expenditure” for accounting purposes when it provides future value to the stockholders and ratepayers by either improving a unit’s availability or extending its useful life and making it more productive over a long period of time. T.T., Sept. 14, 2010, at 25:25-27:11.

320. Allegheny had never before replaced the entire lower slopes at Hatfield 1. T.T., Sept. 20, 2010, at 49:3-12.

321. Based on its own analyses, Allegheny reasonably should have expected an availability increase of 256 hours/year from the Hatfield 1 lower slope PSD Project, which is one-third of the total availability increase of 768 hours that Allegheny expected for all three Hatfield lower slope projects. PTX 633 at R-3 02096 (calculating availability gain as “8 OUT/YR x 4 DAY/YR [*sic*] x 24 HR/DAY”).

322. In the calendar year 1996 preceding the Hatfield 1 lower slope PSD Project, Hatfield 1 had an hourly SO_2 emissions rate, conservatively calculated, of 5.96 tons. PTX

1309-22 (this number represents a calculation by plaintiffs dividing annual emissions, 52,162 tons, by total number of hours in a year, 8,760).

323. In the calendar year 1996 before the Hatfield 1 lower slope PSD Project, Hatfield 1 emitted 40 tons of SO_2 on average when it operated for 6.7 hours. PTX 1309-22 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 5.96 tons calculated in the preceding proposed finding of fact).

324. In the calendar year 1996 preceding the Hatfield 1 lower slope PSD Project, Hatfield 1 had an hourly NO_x emissions rate, conservatively calculated, of 0.981 tons. PTX 1309-22 (this number represents a calculation by plaintiffs dividing annual emissions, 8,597 tons, by total number of hours in a year, 8,760).

325. In the calendar year 1996 before the Hatfield 1 lower slope PSD Project, Hatfield 1 emitted 40 tons of NO_x on average when it operated for 40.8 hours. PTX 1309-22 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 0.981 tons calculated in the preceding proposed finding of fact)..

b. Unit 2 Specific Facts

326. The purpose of the lower slope PSD Project at Hatfield's Ferry 2 was to "improve the availability and reliability of the boiler." PTX 181 at AE_HQ_00567616.

327. Allegheny began planning for this project in early 1995. Docket Item 430 ¶ 48.

328. Allegheny performed the project during a 12 week outage that ran from September 3, 1999 through November 26, 1999. Docket Item 430 ¶ 49.

329. The project involved removing the existing lower slope panels, inlet headers, seal skirt and ash hopper, and replacing those items in their entirety with newly fabricated materials that Allegheny variously described as involving "an improved design," "an upgraded design"

and "a redesign of the lower furnace area in order to take advantage of improvements such as: thicker tubing to address slope erosion and corrosion problems, an improved structural support system to better resist damage from slag falls, improved materials and configuration of the furnace seals to provide a longer service life, and upgraded ash hoppers to improve ash handling capabilities." Docket Item 430 ¶ 50.

330. Allegheny hired outside contractors to fabricate the new materials and to do the demolition, removal and installation work required by the project. Docket Item 430 ¶ 51.

331. In a May 1998 "project economic evaluation system" memorandum, Allegheny explained that by replacing the Hatfield's Ferry 2 "lower slope tubes, first and second pass inlet headers, seal skirt, and ash hoppers" "forced outages in the lower slope area will be reduced to a zero baseline." Docket Item 430 ¶ 53.

332. The total cost of the project was $6,342,917. Docket Item 430 ¶ 54.

333. Allegheny treated the cost of the project as a capital expenditure, not as a maintenance expense, for accounting purposes. Docket Item 430 ¶ 55.

334. A project at an electric generating unit is classified as a "capital expenditure" for accounting purposes when it provides future value to the stockholders and ratepayers by either improving a unit's availability or extending its useful life and making it more productive over a long period of time. T.T., Sept. 14, 2010, at 25:25-27:11.

335. Allegheny had never before replaced the entire lower slopes at Hatfield 2. T.T., Sept. 20, 2010, at 49:3-12.

336. Based on its own analyses, Allegheny reasonably should have expected an availability increase of 256 hours/year from the Hatfield 2 lower slope PSD Project, which is one-third of the total availability increase of 768 hours that Allegheny expected for all three

Hatfield lower slope projects. PTX 633 at R-3 02096 (calculating availability gain as "8 OUT/YR x 4 DAY/YR [*sic*] x 24 HR/DAY").

337. In the calendar year 1998 preceding the Hatfield 2 lower slope PSD Project, Hatfield 2 had an hourly SO_2 emissions rate, conservatively calculated, of 5.60 tons. PTX 1309-24 (this number represents a calculation by plaintiffs dividing annual emissions, 49,057 tons, by total number of hours in a year, 8,760).

338. In the calendar year 1998 before the Hatfield 2 lower slope project, Hatfield 2 emitted, on average, 40 tons of SO_2 when it operated for 7.1 hours. PTX 1309-24 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 5.60 tons calculated in the preceding proposed finding of fact).

339. In the calendar year 1998 before the Hatfield 2 lower slope PSD Project, Hatfield 2 had an hourly NO_x emissions rate, conservatively calculated, of 0.801 tons. PTX 1309-24 (this number represents a calculation by plaintiffs dividing annual emissions, 7,021 tons, by total number of hours in a year, 8,760).

340. In the calendar year 1998 before the Hatfield 2 lower slope project, Hatfield 2 emitted, on average, 40 tons of NO_x when it operated for 49.9 hours. PTX 1309-24 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 0.801 tons calculated in the preceding proposed finding of fact).

c. Unit 3 Specific Facts

341. The purpose of the Hatfield 3 lower slope replacement project was to "minimize future maintenance costs" and to "improve the availability and reliability of the boiler." PTX 1815.

342. Allegheny began planning this project over one year before performing it. Docket Item 430 ¶ 56

343. Allegheny performed the project during an outage that ran from September 20, 1996 through December 1, 1996. Docket Item 430 ¶ 57.

344. The project involved removing the existing lower slope panels, inlet headers, seal skirt and ash hopper, and replacing those items in their entirety with newly fabricated materials that Allegheny variously described as involving “an improved design,” “an upgraded design” and “a redesign of the lower furnace area in order to take advantage of improvements such as: thicker tubing to address slope erosion and corrosion problems, an improved structural support system to better resist damage from slag falls, improved materials and configuration of the furnace seals to provide a longer service life, and upgraded ash hopper to improve ash handling capabilities.” PTX 217.

345. Allegheny hired four different outside contractors to perform the project, although usually only two are required. T.T., Sept. 20, 2010, at 47:20-48:10.

346. The replacement of the lower slopes required disconnecting the headers from the pipes that bring water into them, disconnecting all the old tubes in the lower slopes from the remainder of the waterwalls, moving the new tube panels into place and supporting them until they are connected, and then welding the ends of the new tubes to the rest of the waterwalls. T.T., Sept. 20, 2010, at 46:18-47:15.

347. Over 2,000 welds had to be done to install the new lower slopes. T.T., Sept. 20, 2010, at 48:11-48:15.

348. The work was done in two ten hour daily shifts, with approximately 52 people working on each shift for six days a week for eight weeks. T.T., Sept. 20, 2010, at 48:16-49:2.

349. Allegheny had never before replaced the entire lower slopes at Hatfield 3. T.T., Sept. 20, 2010, at 49:03-12.

350. The final cost of the project was $5,180,755, more than $3,000,000 greater than the original estimate. PTX 217; PTX 184 at AE_DUN_00131833.

351. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. Docket Item 430 ¶ 60.

352. A project at an electric generating unit is classified as a "capital expenditure" for accounting purposes when it provides future value to the stockholders and ratepayers by either improving a unit's availability or extending its useful life and making it more productive over a long period of time. T.T., Sept. 14, 2010, at 25:25-27:11.

353. Based on its own analyses, Allegheny reasonably should have expected an availability increase of 256 hours/year from the Hatfield 3 lower slope PSD Project, which is one-third of the total availability increase of 768 hours that Allegheny expected for all three Hatfield lower slope projects. PTX 633 at R-3 02096 (calculating availability gain as "8 OUT/YR x 4 DAY/YR [*sic*] x 24 HR/DAY").

354. In the calendar year 1995 before the Hatfield 3 lower slope PSD Project, Hatfield 3 had an hourly SO_2 emissions rate, conservatively calculated, of 5.70 tons. PTX 1309-21 (this number represents a calculation by plaintiffs dividing annual emissions, 49,911 tons, by total number of hours in a year, 8,760).

355. In the calendar year 1995 before the Hatfield 3 lower slope project, Hatfield 3 emitted, on average, 40 tons of SO_2 when it operated for 7.0 hours. PTX 1309-21 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 5.70 tons calculated in the preceding proposed finding of fact).

356. In the calendar year 1995 before the Hatfield 3 lower slope PSD Project, Hatfield 3 had an hourly NO_x emissions rate, conservatively calculated, of 0.893 tons. PTX 1309-21 (this number represents a calculation by plaintiffs dividing annual emissions, 7,823 tons, by total number of hours in a year, 8,760).

357. In the calendar year 1995 before the Hatfield 3 lower slope project, Hatfield 3 emitted, on average, 40 tons of NO_x when it operated for 44.8 hours. PTX 1309-21 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 0.893 tons calculated in the preceding proposed finding of fact).

3. The Hatfield's Ferry 2 Pendant Reheater PSD Project

358. Allegheny began planning the Hatfield 2 pendant reheater PSD Project at least 18 months before the outage at which it was performed. Docket Item 430 ¶ 40.

359. Problems in the pendant reheater had been causing one forced outage per year. PTX 715 at AE_DUN_00194043.

360. Allegheny predicted an additional two forced outages per year if the pendant reheater were not replaced. PX 715 at AE_DUN_00194043.

361. Allegheny concluded that replacing the pendant reheater "will improve the availability of Hatfield's Number 2 boiler. . . ." PTX 715 at AE_DUN_00194035.

362. The Hatfield 2 reheater project would not have any affect on the unit's capacity or efficiency. T.T., Sept. 20, 2010, at 33:14-24.

363. Allegheny assumed that there would be no forced outages caused by the pendant reheater for 30 years into the future if the project were done. PTX 715 at AE_DUN_00194042.

364. Allegheny assumed that Hatfield 2 would generate electricity for at least an additional 72 hours per year after the projects because the unit would not be shut down for a 72 hour forced outage each year as it had been before the projects. PTX 715 at AE_DUN_00194035.

365. Allegheny estimated that it would spend $13,013,249 on replacement energy during the next 30 years if the projects were not done. PTX 715 at AE_DUN_00194044.

366. Allegheny assume that there would be no cost of replacement energy for 30 years if the project were done. PTX 715 at AE_DUN_00194047.

367. Allegheny performed the project during an outage that ran from September 25, 1993 to December 3, 1993. Docket Item 430 ¶ 41.

368. The project involved removing the existing reheater assemblies and crossover tubes and replacing them with newly fabricated assemblies made of a different material that Allegheny anticipated would be more resistant to corrosion than the existing assemblies. Docket Item 430 ¶ 42.

369. The pendant reheater consisted of 125 pendants or assemblies of tubing suspended from a header near the top of the boiler. T.T., Sept. 20, 2010, at 13:3-14:1; PTX 715 at AE_DUN00194039.

370. Each of the 125 pendants weighs several thousand pounds, contains 700 feet of tubing and is approximately 40 feet high and twenty feet long. T.T., Sept, 20, 2010, at 15:06-15:10, 22:1-22:2.

371. The total tubing in the pendant reheater is approximately 17 miles long. T.T., Sept. 20, 2010, at 13:3-14:1; PTX 715 at AE_DUN_00194040.

372. A total of 2,265 individual welds were required to install the tubing of the new pendant reheater. PTX 730 at AE_HF_00039483-000039492.

373. During the eight weeks required to remove the old reheater and replace it with a new one, 80 people worked every day, in two ten hour shifts six days a week. T.T., Sept. 20, 2010, at 23:22-24:07.

374. The total cost of the project was $5,692,777. Docket Item 430 ¶ 44.

375. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. Docket Item 430 ¶ 45.

376. A project at an electric generating unit is classified as a "capital expenditure" for accounting purposes when it provides future value to the stockholders and ratepayers by either improving a unit's availability or extending its useful life and making it more productive over a long period of time. T.T., Sept. 14, 2010, at 25:25-27:11.

377. The work was performed by outside contractors, not Allegheny's own maintenance employees. Docket Item 430 ¶ 46.

378. Although Allegheny had previously replaced some of the crossover tubes, it had never previously replaced the entire pendent reheater or all of the crossover tubes. Docket Item 430 ¶ 47.

379. The pendant reheater that was replaced had caused 63 hours of outage between October 1990 and September 1992. PTX 77.

380. Based on its own analyses, Allegheny reasonably should have expected an availability increase of 72 hours/year from the Hatfield 2 pendant reheater PSD Project, given that one-third of the 216-hour availability gain that Allegheny incorporated in its economic analysis was due to outages that had been occurring in the past due to problems with the

pendant reheater. PTX 715 at AE_DUN_00194044 (calculating availability gain of 216 hours/year as "3 Outages/Year x 3 Days/Outage x 24 Hours/Day," reflecting anticipated elimination of (a) one outage per year that had been happening in the past and would continue, and (b) two outages per year that were not yet occurring but would occur if Allegheny did not undertake the project).

381. In the calendar year 1992 before the Hatfield 2 pendant reheater PSD Project, Hatfield 2 had an hourly SO_2 emissions rate, conservatively calculated, of 5.88 tons. PTX 1309-18 (this number represents a calculation by plaintiffs dividing annual emissions, 51,485 tons, by total number of hours in a year, 8,760).

382. In the calendar year 1992 before the Hatfield 2 pendant reheater project, Hatfield 2 emitted 40 tons of SO_2 on average when it operated for 6.8 hours. PTX 1309-18 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 5.88 tons calculated in the preceding proposed finding of fact).

383. In the calendar year 1992 before the Hatfield 2 pendant reheater PSD Project, Hatfield 2 had an hourly NO_x emissions rate, conservatively calculated, of 1.39 tons. PTX 1309-18 (this number represents a calculation by plaintiffs dividing annual emissions, 12,159 tons, by total number of hours in a year, 8,760).

384. In the calendar year 1992 before the Hatfield 2 pendant reheater project, Hatfield 2 emitted 40 tons of NO_x on average when it operated for approximately 28.8 hours. PTX 1309-18 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 1.39 tons calculated in the preceding proposed finding of fact).

4. The Hatfield's Ferry 1 Secondary Superheater Outlet Header PSD Project

385. The secondary superheater outlet header ("SSOH") replacement projects involved the complete replacement of both SSOHs in each Hatfield unit. PTX 565.

386. Allegheny began planning the projects over two years before performing them. Docket Item 430 ¶ 34.

387. The Hatfield units had experienced periodic forced outages due to leaks in the stub welds of the SSOHs. PTX 213 at R-3 02950.

388. Allegheny estimated that each Hatfield unit would experience one forced outage per year related to the SSOH problems if they were not replaced. PTX 565 at AE_DUN_00412489.

389. Hatfield 1 had experienced once forced outage in 1995 and two in 1997 related to the SSOHs. PTX 565 at AE_DUN_00412488; PTX 81.

390. The purpose of the SSOH replacement projects was to improve the availability and reliability of the Hatfield boilers. PTX 723 at AE_HQ_00369760.

391. The success of the Allegheny employees responsible for the SSOH projects at Hatfield 1 was to be measured by, among other things, an "increase in availability" at Hatfield 1. PTX 723 at AE_HQ_00369760.

392. After the Hatfield 1 SSOH project was completed, Allegheny predicted that the new and upgraded SSOHs would "drastically increase Unit 1's reliability." PTX 215 at AE_DUN_00005313.

393. The Hatfield 1 SSOH project would not affect the capacity or efficiency of the unit. T.T., Sept. 20, 2010, at 33:25-34:6.

394. Allegheny performed the SSOH replacement project at Hatfield unit 1 during an outage that took place from October 11, 1997 to December 20, 1997. Docket Item 430 ¶ 33.

395. The project involved replacing both secondary superheater outlet headers at Hatfield Unit 1 with newly fabricated outlet headers that were of an upgraded design and a stronger material than were the original outlet headers. Docket Item 430 ¶ 35.

396. The work was performed by outside contractors using materials fabricated by outside contractors. Docket Item 430 ¶ 36

397. Each SSOH that was replaced was sixty feet long and weighed 90,000 pounds. PTX 758 at AE_MIT00033387; T.T., Sept. 20, 2010, at 26:4-7, 35:14-35:18.

398. Each header had approximately 100 tubes connected to it. T.T., Sept. 20, 2010, at 34:10-35:6.

399. These tubes had to be cut free from the header and a rigging constructed for each tube to prevent it from falling. T.T., Sept. 20, 2010, at 34:10-35:6.

400. To remove the old and install the new headers, the outside contractors cut a hole in the roof of the building and used a huge crane to reach over the top of the building to lift the old headers out and install the new ones. T.T., Sept. 20, 2010, at 35:7-35:13.

401. Each 90,000 pound SSOH had to be cut into five pieces to make it easier to lift them out. T.T., Sept. 20, 2010, at 35:14-35:18.

402. The new SSOHs weighed 40,000 pounds each and the crane lifted them through the hole in the roof in two parts. T.T., Sept. 20, 2010, at 35:19-36:6; PTX 758 at AE_MIT00033387.

403. After the new SSOHs were lifted into the boiler, they were rigged in place and the hundreds of tubes were welded back to the tube stubs on the new header. T.T., Sept. 20, 2010, at 35:14-36:6.

404. The total cost of the project was $2,513,016. Docket Item 430 ¶ 37.

405. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. Docket Item 430 ¶ 38.

406. A project at an electric generating unit is classified as a "capital expenditure" for accounting purposes when it provides future value to the stockholders and ratepayers by either improving a unit's availability or extending its useful life and making it more productive over a long period of time. T.T., Sept. 14, 2010, at 25:25-27:11.

407. Before this project, Allegheny had not previously replaced the Hatfield 1 secondary superheater outlet headers. Docket Item 430 ¶ 39.

408. In the calendar year 1996 before the Hatfield 1 secondary superheater outlet header PSD Project, Hatfield 1 had an hourly SO_2 emissions rate, conservatively calculated, of 5.96 tons. PTX 1309-22 (calculation by plaintiffs dividing annual emissions, 52,162 tons, by total number of hours in a year, 8,760).

409. In the calendar year 1996 before the Hatfield 1 secondary superheater outlet header PSD Project, Hatfield 1 emitted, on average, 40 tons of SO_2 when it operated for 6.7 hours. PTX 1309-22 (calculation by plaintiffs dividing 40 tons by the hourly rate of 5.96 tons calculated in the preceding proposed finding of fact).

410. In the calendar year 1996 before the Hatfield 1 secondary superheater outlet header PSD Project, Hatfield 1 had an hourly NO_x emissions rate, conservatively calculated, of

0.981 tons. PTX 1309-22 (calculation by plaintiffs dividing annual emissions, 8,597 tons, by total number of hours in a year, 8,760).

411. In the calendar year 1996 before the Hatfield 1 secondary superheater outlet header project, Hatfield 1 emitted, on average, 40 tons of NO_x when it operated for 40.8 hours. PTX 1309-22 (calculation by plaintiffs dividing 40 tons by the hourly rate of 0.981 tons calculated in the preceding proposed finding of fact).

5. The Mitchell 3 Lower Slope PSD Project

412. In the five-and-one-half years before the Mitchell lower slope project was approved in 1994, the unit had been experiencing 3.8 tube leaks per year. PTX 293 at AE_DUN_00191935.

413. There was an average of 71 forced outage hours per year over the five years before the project was commenced. PTX 83.

414. Allegheny expected the availability of Mitchell 3 to decline further unless the panels were replaced. PTX 293 at AE_DUN_00191935.

415. The purpose of the Mitchell lower slope project was "to improve plant availability." PTX 706 at R-3 06901.

416. Allegheny expected the Mitchell lower slope project to eliminate forced outages in the future related to the lower slope. T.T., Sept. 23, 2010, at 126:8-127:5.

417. Allegheny hoped the Mitchell lower slope project would cause the unit to operate better in the future than it had in the past. T.T., Sept. 23, 2010, at 128:22- 129:3.

418. The Mitchell lower slope project occurred during an outage from October 7, 1994 through December 30, 1994. Docket Item 430 ¶ 67.

419. The project consisted of replacing 24 front and rear ash hopper panels at Mitchell 3. Docket Item 430 ¶ 68.

420. The total cost of the project was $626,402. Docket Item 430 ¶ 69.

421. The work was performed by outside contractors. Docket Item 430 ¶ 70.

422. Allegheny treated the cost of the project as a capital expenditure, not a maintenance expense, for accounting purposes. PTX 706.

423. This was the first time Allegheny had done a project of this magnitude on the Mitchell 3 lower slope. T.T., Sept. 20, 2010, at 55:12-15.

424. A project at an electric generating unit is classified as a "capital expenditure" for accounting purposes when it provides future value to the stockholders and ratepayers by either improving a unit's availability or extending its useful life and making it more productive over a long period of time. T.T., Sept. 14, 2010, at 25:25-27:11.

425. Based on its own analyses, Allegheny reasonably should have expected an availability increase of 182 hours/year from the Mitchell 3 lower PSD Project, given that the unit had already been experiencing 3.8 outages per year due to leaks in the lower slope panels, and a conservative estimate of the length of a forced outage due to such a leak would be 48 hours. PTX 706 at R-3 06901 (as calculated by plaintiffs, 3.8 outages per year x 48 hours = 182.4 hours).

426. In the calendar year 1993 before the Mitchell 3 lower slope PSD Project, Mitchell 3 had an hourly NO_x emissions rate, conservatively calculated, of 0.681 tons. PTX 1309-37 (this number represents a calculation by plaintiffs dividing annual emissions, 5,964 tons, by total number of hours in a year, 8,760).

427. In the calendar year 1993 before the Mitchell 3 lower slope PSD Project, Mitchell 3 emitted 40 tons of NO_x on average when it operated for 58.5 hours. PTX 1309-37 (this number represents a calculation by plaintiffs dividing 40 tons by the hourly rate of 0.681 tons calculated in the preceding proposed finding of fact).

B. <u>Routine Maintenance</u>

428. Robert H. Koppe was accepted by the Court as an expert in power plant maintenance practices and he testified about the difference between routine maintenance and the major capitalized component replacements in this case.

429. Mr. Koppe has a master's of science degree from Ohio State University in nuclear power plant engineering and has completed all the courses toward a doctorate in nuclear engineering at the Massachusetts Institute of Technology. T.T., Sept. 14, 2010, at 194:8-13.

430. After working for several years in the nuclear engineering group at the Consolidated Edison Company in New York City, Mr. Koppe began to work for a consulting firm on issues related to electric power plant availability, performance; and maintenance practices; the majority of the company's clients were electric utilities or a utility-funded research organization. *Id.* at 194:14

431. As Mr. Koppe testified, utilities have historically used the term "routine maintenance" to refer to "all the little things we do every day to keep the plant operating." T.T., Sept. 14, 2010, at 216:7-22; T.T., Sept. 20, 2010, at 8:11-19, 56:18-25.

432. The term "routine maintenance" and terms like it are used to characterize activities that are different in every respect from the kinds of component replacement activities at issue in this case. T.T., Sept. 20, 2010, at 58:25-63:13.

433. Allegheny had the same understanding of routine maintenance. For example, Jeffrey Mooney, who was employed by Allegheny from 1988 to at least 2007 as a plant engineer and maintenance supervisor, explained that "daily routine maintenance" is the kind of maintenance that is done simply to "fix what breaks" D.T. (Jeffrey Mooney), Aug. 22, 2007, at 99:17-19.

434. Mr. Mooney further explained that routine maintenance is typically undertaken on redundant equipment or equipment that can be shut down temporarily without taking the unit off-line. D.T. (Jeffrey Mooney), Aug. 22, 2007, at 20:24-21:3.

435. Another Allegheny employee, Peter Kotsenas, who was employed as a maintenance superintendent at the Hatfield units in the 1990s, explained that a similar term – "regular maintenance" – involves smaller projects that can be done under the power station's operating and maintenance budget and would not necessarily have a work order number associated with them. D.T. (Peter Kotsenas), Aug. 30, 2007, at 131:13-20.

436. A former Allegheny employee, Keith Pritts, who was a plant engineer at the Armstrong power station, described the replacement of a small piece of equipment, such as a small air compressor, as a routine project. D.T. (Keith Pritts), Sept. 6, 2007, at 13:20-14:10.

437. Allegheny employees also referred to "regular maintenance" as "base maintenance" PTX 156 at AE_HQ_00482442; D.T. (David Piktel), Sept. 29, 2009, at 103:23-104:18. Base maintenance is required to operate the plant on a daily basis, and includes day-to-day activities such as changing oil in components, maintaining the grounds, snow plowing in wintertime, grass cutting in summertime. D.T. (David Piktel), Sept. 29, 2009, at 104:2-104:18.

438. The projects that are undertaken during outages, by contrast, are intended to extend the life of the unit. D.T. (Jeffrey Mooney), Aug. 22, 2007, at 99:17-21.

439. Indeed, in testimony before the Pennsylvania Public Utilities Commission in 1992, Donald Feenstra, then Allegheny's Director of Power Stations, distinguished between routine maintenance and the kind of large-scale replacements at issue here, explaining that Allegheny has an extensive program to perform both routine base maintenance and "more complex special maintenance projects." PTX 156 at AE_HQ_00482442.

440. Mr. Feenstra further explained that "routine maintenance" is performed by Allegheny employees, while projects that are performed by outside contractors have "physical and technical requirements" that are beyond the "capability of the Company's full-time personnel." PTX 156 at AE_HQ_00482452.

441. Routine maintenance, such as repairing a leak in single tube in a deteriorating component, can solve an immediate problem that caused an outage at a generating unit, but it cannot change the expected amount of future outage time due to the deteriorating component. T.T., Sept. 20, 2010, at 15:1-16:22.

442. Routine maintenance thus cannot improve a generating unit's availability. T.T., Sept. 20, 2010, at 15:1-16:22, 60:8-61:3.

443. By contrast, replacing an entire deteriorating component eliminates the likelihood or inevitability of many future problems in that component that otherwise would have happened and can improve a generating unit's availability. T.T., Sept. 20, 2010, at 60:8-61:10.

444. At least 2,000 routine maintenance tasks are performed at a generating unit every year. T.T., Sept. 20, 2010, at 57:20-58:6.

445. Replacement of a major section of boiler tubes at a unit occurs approximately once every ten years. T.T., Sept. 20, 2010, at 62:1-62:16.

446. Major component replacements were much less common at individual units and in the industry before the 1980s than they have been since. T.T., Sept. 20, 2010, at 63:14-64:20

447. Utility life extension programs that began in the 1980s increased the frequency of major component replacements. T.T., Sept. 20, 2010, at 63:14-65:24.

448. There are now 800 utility coal fired electric generating units operating beyond their originally intended lives. T.T., Sept. 20, 2010, at 32:07-33:9.

449. Approximately 270 major component replacements are done each year in the 1000 utility coal fired electric generating units compared to 2 million routine maintenance tasks. T.T., Sept. 20, 2010, at 65:25-68:12.

450. If replacements of major components were considered to be routine, utilities could indefinitely replace major components piecemeal without ever triggering a requirement to install pollution controls under the PSD regulations. T.T., Sept. 28, 2010, at 135:20-136:6.

C. Emissions Analyses for the PSD Projects

1. Mr. Koppe's Availability Analyses – His General Approach

451. Mr. Koppe was also accepted by the Court as an expert in power plant availability and performance based on his 35 year career as a consultant helping utilities improve the availability of their generating units. T.T., Sept. 14, 2010, at 200:5-13.

452. In particular, Mr. Koppe played a principal role in the development of the Generating Availability Data System ("GADS") for the North American Electric Reliability Corporation – a data base that was created in response to a crisis of declining availability of

new electric generating units and to which 90 percent of the United States' electric utilities submit performance data and upon which they rely to track the performance of their units. *Id.* at 197:23-199:21.

453. Thus, Allegheny reports to GADS every time one of its units is in a forced outage, the number of hours of the forced outage, the cause of the forced outage and the location in the unit where the problem occurred. T.T., Sept. 23, 2010, at 19:16-22:14; DTX 1399.

454. Allegheny also created and maintained a detailed log that recorded the precise location of each boiler tube leak that caused a forced outage at each generating unit. T.T., Sept. 27, 2010, at 168:04-169:06.

455. As set forth at Plaintiffs' Findings of Fact 128, when Allegheny replaced a major component that had been causing forced outages, it expected to have no forced outages due to the new component throughout its useful life.

456. Mr. Koppe, quantified the increase in availability that Allegheny should have expected after each of the major component replacements at issue in this case. T.T., Sept. 20, 2010, at 193:14-194:5.

457. Mr. Koppe has spent a large part of his 35-year career as a consultant hired by electric utilities – approximately 30 to 35 of them – to do the same task as he did in this case: evaluate whether large capital projects should be expected to increase unit availability. T.T., Sept. 14, 2010, at 195:7-196:18.

458. The methodology he used in this case to evaluate whether a project should have been expected to increase unit availability is the same methodology that he used throughout his career when hired by utilities and providing testimony to public utility commissions, and the

same methodology that he has seen utilities themselves use. T.T., Sept. 14, 2010, at 214:19-215:22.

459. Mr. Koppe concluded that Allegheny should have expected a net increase in unit availability if (a) the project itself would increase future availability by reducing the number of forced outages at the unit and (b) there was no reason for Allegheny to expect that other problems at the unit after the project was completed would cause a decrease in unit availability. T.T., Sept. 20, 2010, at 72:13-75:3.

a. Expectations That the PSD Projects Would Increase Availability

460. To determine whether Allegheny should have expected the projects to increase availability, Mr. Koppe first reviewed Allegheny's documents about each of the PSD projects to determine precisely what equipment Allegheny was replacing. T.T., Sept. 20, 2010, at 93:7-23.

461. Mr. Koppe, one of the creators of the GADS system, then reviewed Allegheny's GADS event data and its internal documents in the five years before the component was replaced, to identify the number and length of forced outages caused by problems with that component during those five years. T.T., Sept. 20, 2010, at 93:18-94:7, 96:25-97:10.

462. For each of the PSD projects alleged in the complaint, Mr. Koppe prepared a table identifying the outages that had been caused by problems with the component that were addressed by its replacement. T.T., Sept. 20, 2010, at 93:18-97:18; PTX 77 - PTX 87.

463. The tables classified the outages as either "partially documented" or "fully documented." T.T., Sept. 20, 2010, at 96:25-98:02.

464. The partially documented outages reflected situations where Allegheny's documentation was not sufficient to identify with certainty whether or not the outage had been

caused by a problem in the component that was being replaced. T.T., Sept. 20, 2010, at 96:25-97:18.

b. Expectations About the Effect of Everything Else

465. Mr. Koppe concluded that Allegheny should have expected the amount of outage time due to other components in the unit to stay the same or decrease slightly after the PSD projects. T.T., Sept. 20, 2010, at 74:13-75:3.

466. First, Allegheny was doing other repairs and replacements at the units either shortly before or at the same time as the PSD projects; this other work would also have the effect of reducing forced outages. T.T., Sept. 20, 2010, at 92:9-16.

467. For example, the Hatfield Unit 1 secondary superheater outlet headers were replaced during the same outage that the lower slope was replaced Docket Item 430 ¶¶ 27,33.

468. During the outage in which the Hatfield Unit 2 lower slope was replaced, panels were also replaced on the north and south furnace walls. PTX 193 at AE_HF00068257.

469. Allegheny replaced the reheater in Unit 1 in 1992, a year before replacing the Unit 2 reheater and installed tube shields on the Unit 2 economizer in 1991. PTX 718 at AE_HQ_021572.

470. Second, Allegheny was planning to increase the interval between planned outages at the units at issue in this case. T.T., Sept. 20, 2010, at 89:11-90:12.

471. As Allegheny witness Paul Kramer testified, “planned outages typically run in the six to eight week time frame, so that they can represent 11 to 20 percent of a unit’s annual availability.” T.T., Sept. 22, 2010, at 195:7-12.

472. As Mr. Kramer further testified, a unit in a year without a planned outage will be available 10 to 20 percent more of the time than a unit in a year with a planned outage. T.T., Sept, 22, 2010, 197:22-198:6.

473. Since planned outages substantially reduce a unit's availability, fewer planned outages would result in substantially increased unit availability. T.T., Sept. 22, 2010, at 198:7-13.

474. Indeed, Allegheny expected its planned reduction in the frequency of planned outages to increase availability by 1 ½ to 2 percent. T.T., Sept. 20, 2010, at 90:13-22; PTX 716 at AE_HQ_00465788 - AE_HQ_00465789.

475. Mr. Koppe found that the PSD projects should have been expected to increase unit availability because (a) the project would reduce forced outage time due to the replaced component and (b) the outage time due to everything else at the unit should have been expected to remain the same. T.T., Sept. 20, 2010, at 72:13-75:3.

476. From these conclusions, Mr. Koppe determined that Allegheny should have expected the effect of the PSD Projects to increase net unit availability from the past to the future. T.T., Sept. 20, 2010, at 72:13-75:3.

477. For one project in plaintiffs' complaint, however – the Hatfield's Ferry 2 1999 secondary superheater outlet header project – Mr. Koppe did not find any fully documented outages. *See* PTX 79.

2. Dr. Rosen's PSD Emissions Calculations – His General Approach

478. For the purpose of this litigation, plaintiffs hired an expert, Dr. Richard Rosen, to offer opinions as to whether reasonable preconstruction emissions projections made pursuant to

the PSD regulations would have shown significant net emissions increases. T.T. Sept. 20, 2010, at 10:4-11:3.

479. Dr. Rosen has a Ph.D. in physics and has spent the last 30 years evaluating a wide range of energy and environmental policy issues for a not-for-profit research institution. T.T., Sept. 21, 2010, at 179:19-181:2. Dr. Rosen performed his own emissions calculations to develop those opinions. *Id.* at 10:2-11:8.

a. The Methodology Dr. Rosen Used

480. To arrive at his opinions, Dr. Rosen looked at six common-sense factors that influence the amount of emissions generated by a coal-fired generating unit. T.T., Sept. 21, 2010, at 19:20-20:22.

481. The first factor that Dr. Rosen considered is *the rate or intensity with which the unit is used*. T.T., Sept. 21, 2010, at 20:6-9.

482. The technical term for the rate of usage is the *capacity factor*, which is the percentage of the possible total output of electricity from the unit that the unit actually generates. T.T., Sept. 21, 2010, at 22:23-23:8.

483. The rate of unit use or capacity factor, in turn reflects two other factors: the unit's equivalent availability factor and the unit's utilization factor. T.T., Sept. 21, 2010, at 42:10-46:3.

484. The utilization factor is the part of Dr. Rosen's methodology that incorporates the effect of increases or decreases in demand for electricity as they might affect usage of the generating unit. T.T., Sept. 21, 2010, at 72:16-75:19.

485. The rate of unit use, or capacity factor, is calculated by multiplying the EAF by the utilization factor. *Id.* at 42:10-44:24.

486. So, for example, if a unit is available to operate 80 percent of the time in a year, and runs 70 percent of the time that it is available, its capacity factor is 0.80 times 0.7, which is 0.56. T.T., Sept. 21, 2010, at 44:17-24.

487. The second factor that Dr. Rosen considered is *the time period over which the emissions are being generated*. T.T., Sept. 21, 2010, at 20:10-11.

488. Because Dr. Rosen evaluated annual emissions, he looked at average emissions over the course of one year, or 8,760 hours. T.T., Sept. 21, 2010, at 23:12-14.

489. The third factor that Dr. Rosen considered is *the size of the unit*: T.T., Sept. 21, 2010, at 20:12-13.

490. The technical term for this is *unit capacity,* which is usually measured in megawatts. T.T., Sept. 21, 2010 at 23:6-7.

491. The fourth factor that Dr. Rosen considered is *the efficiency of the unit*. T.T., Sept. 21, 2010, at 20:14-16.

492. The technical term for this is *heat rate*, which measures the efficiency with which the generating unit uses the energy obtained from burning the coal, *i.e.*, the amount of heat it takes to generate a kilowatt-hour of electricity. T.T., Sept. 21, 2010, at 24:9-25:1; T.T., Sept. 20, 2010, at 10:6-16; *see also United States v. Ohio Edison*, 276 F. Supp. 2d 829, 837 (S.D. Ohio 2003) ("Heat rate measures the quantity of heat necessary to generate a kilowatt-hour of electricity") (citing testimony of Mr. Koppe).

493. The fifth factor that Dr. Rosen considered is *the energy content of the coal being burned*. T.T., Sept. 21, 2010, at 20:17-20.

494. The technical term for this is *heat content.* T.T., Sept. 21, 2010, at 26:17-18.

495. The fifth factor that Dr. Rosen considered is *the emissions factor*. T.T., Sept. 21, 2010, at 20:21-22.

496. This represents the amount of pollution generated per ton of coal burned. T.T., Sept. 21, 2010, at 28:12-18.

497. The emissions factor for SO_2 reflects the sulfur content of the coal being burned, while the emissions factor for NO_x reflects the type of boiler in the generating unit. T.T., Sept. 21, 2010, at 28:19-29:7.

498. Dr. Rosen embodied these factors that govern the amount of emissions – availability factor, utilization factor, total hours in a year, unit capacity, heat rate, heat content and emissions factor – in five mathematical equations. *Id.* at 21:15-24 (discussing the five equations).

499. The first equation is:

$$(1) \quad \boxed{\begin{array}{c}\textit{availability}\\ \textit{factor}\\ \textit{(“EAF”)}\end{array}} \text{ x } \boxed{\begin{array}{c}\textit{utilization}\\ \textit{factor}\\ \textit{(“UF”)}\end{array}} = \boxed{\begin{array}{c}\textit{capacity}\\ \textit{factor}\\ \textit{(“CF”)}\end{array}}$$

T.T., Sept. 21, 2010, at 41:21-45:1..

500. The second equation is:

$$(2) \quad \boxed{\begin{array}{c}\textit{capacity}\\ \textit{factor}\end{array}} \text{ x } \boxed{\begin{array}{c}\textit{total hours in}\\ \textit{a year}\\ \textit{(“TH”)}\end{array}} \text{ x } \boxed{\begin{array}{c}\textit{unit capacity}\\ \textit{(“UC”)}\end{array}} = \boxed{\begin{array}{c}\textit{amount of}\\ \textit{electricity}\\ \textit{generated}\end{array}}$$

T.T., Sept. 21, 2010, at 22:19-23:19..

501. The third equation is:

$$(3) \quad \boxed{\begin{array}{c}\textit{amount of}\\ \textit{electricity}\\ \textit{generated}\end{array}} \text{ x } \boxed{\begin{array}{c}\textit{heat rate}\\ \textit{(“HR”)}\end{array}} = \boxed{\begin{array}{c}\textit{Btu}\\ \textit{consumption}\end{array}}$$

T.T., Sept. 21, 2010, at 24:9-25:16.

502. The fourth equation is:

$$(4) \quad \boxed{\textit{Btu consumption}} \div \boxed{\textit{coal heat content (``HC'')}} = \boxed{\textit{amount of coal burned}}$$

T.T., Sept. 21, 2010, at 26:2-21.

503. The fifth equation is:

$$(5) \quad \boxed{\textit{amount of coal burned}} \times \boxed{\textit{emissions factor (``EF'')}} = \boxed{\textit{amount of emissions}}$$

T.T., Sept. 21, 2010, at 28:9-29..

504. These five equations can be combined into one long equation:

$$\boxed{EAF} \times \boxed{UF} \times \boxed{TH} \times \boxed{UC} \times \boxed{HR} \div \boxed{HC} \times \boxed{EF} = \boxed{\textit{amount of emissions}}$$

T.T., Sept. 21, 2010, at 46:20-47:11.

505. Each of Dr. Rosen's five equations represents a standard, undisputed relationship governing power plant operations. T.T., Sept. 21, 2010, at 45:2-21 (step 1); *id.* at 23:22-24:8; *id.* at 25:17-26:1 (step 3); *id.* at 27:17-22 (step 4); *id.* at 29:8-13 (step 5); *see also*, *e.g.*, PTX 1088 at EP001104 (1985 Electric Power Research Institute report defining "utilization" as capacity factor divided by availability factor, as in Dr. Rosen's first step).

506. Allegheny itself used steps 2 through 5 of the methodology Dr. Rosen used here to calculate emissions in May 1990, three years before any of the projects at issue in this case. T.T., Sept. 21, 2010, at 32:18-35:21.

507. Allegheny again used steps 2 through 5 to calculate emissions in January 1996. T.T., Sept. 21, 2010, at 35:22-39:5.

508. A 1989 college textbook taught students to use the relationships in steps 2 through 5 to calculate power plant emissions. T.T., Sept. 21, 2010, at 39:6-41:17.

b. How Dr. Rosen Applied His Five-Equation Methodology to Calculate Projected Emissions Changes for the PSD Claims

509. To arrive at his opinions on whether Allegheny should have expected the PSD Projects to increase emissions of SO_2 and NO_x, Dr. Rosen calculated what are known as "actual to projected actual" emissions changes from the projects, if any, based on the information available to Allegheny before the projects. T.T., Sept. 21, 2010, at 16:25-17:12.

510. To do so he applied his five-equation methodology to calculate (1)actual pre-project emissions and (2) anticipated post-project emissions, for each of the PSD Projects, and then subtracted the former from the latter to calculate the expected change, if any, in emissions. *See*, *e.g.*, T.T., Sept. 21, 2010, at 47:17-21; PTX 1969 (sample of Dr. Rosen's calculations).

i. Selecting the Pre-Project "Baseline" Period and the Post-Project Period

511. To apply his method, Dr. Rosen started by selecting "baseline" periods for each project. T.T., Sept. 21, 2010, at 50:22-51:2.

512. The "baseline" period represents a two-year period prior to the project which serves as the reference period for calculating pre-project emissions. *Id.* at 51:7-13.

513. Dr. Rosen selected the baseline period for each of the PSD Projects using the "average generation" or "average two of five" approach, which looks at the five years prior to the project and selects the 24-month period during that five years during which the average level of electricity generation most closely matched the average level of electricity generation during the entire five-year period. T.T., Sept. 21, 2010, at 12:14-18, 51:14-54:14.

514. Later in the case, at the request of plaintiffs' counsel, Dr. Rosen performed additional emissions calculations the "high two-of-five" approach. T.T., Sept. 21, 2010, at 97:6-20.

515. In that approach, he again considered the five-year period before the project and selected the 24-month period during that five-year period during which the level of emissions were the highest. T.T., Sept. 21, 2010, at 97:6-20.

516. Because the "high two of five" approach looks at the amount of emissions, it can and did produce different baseline periods for the two pollutants at issue in this litigation, SO_2 and NO_x. T.T., Sept. 21, 2010, at 102:20-103:8; PTX 2175.

517. In addition to selecting a pre-project period, Dr. Rosen also had to select post-project reference periods: the approach he took for selecting the post-project period was to use the twenty-four month period that followed each project. *See, e.g.*, T.T., Sept. 21, 2010, at 14:3-20.

518. Once Dr. Rosen knew the two-year baseline period and two year post-project period he was using for each project, he determined the appropriate input values in the pre-project baseline period and the post-project period for each of the factors in his five equations: unit availability factor, unit utilization factor, hours in a year, unit capacity, unit heat rate, coal heat content, and emissions factor. T.T., Sept. 21, 2010, at 51:1-6.

ii. Determining the Pre-Project and Expected Post-Project Availability Factors

519. To determine the change in availability factor, if any, Dr. Rosen relied on Mr. Koppe's conclusions regarding expected changes in unit availability. T.T., Sept. 21, 2010, at 59:3-12.

520. First, Dr. Rosen calculated the unit EAF for the pre-project baseline period, using Allegheny's GADS data. T.T., Sept. 21, 2010, at 58:19-25.

521. Then he calculated the expected post-project unit EAF by adjusting the pre-project EAF by the increase in the amount of hours of availability during the baseline period according to Mr. Koppe's tables. T.T., Sept. 21, 2010, at 59:13-62:24.

522. In so doing, Dr. Rosen did not use the outage hours on the tables that were only partially documented. T.T., Sept. 21, 2010, at 62:22-63:7.

523. For the project in plaintiffs' complaint where Mr. Koppe did not find any fully documented outages, the Hatfield's Ferry Unit 2 secondary superheater outlet header project, Dr. Rosen did not assume that the project would increase unit availability and therefore his calculations showed no emissions increases. T.T., Sept. 21, 2010, at 64:20-65:12.

524. Plaintiffs stipulated to the withdrawal of the portions of their claims relating to this project. Docket Item 245 ¶ 1(a).

iii. Determining the Pre-Project and Expected Post-Project Utilization Factors

525. Dr. Rosen determined that it was appropriate to hold the utilization factor constant based on his understanding of industry best practices and the PSD regulations. T.T., Sept. 21, 2010, at 72:16-24.

526. With regard to the industry best practice, Dr. Rosen relied on a 1985 report from the Electric Power Research Institute, or EPRI, a well-regarded research institute funded by the electric power industry. *Id.* at 45:2-16 (nature of EPRI), *id.* at 76:25-77: 6 (EPRI report); PTX 1088 (entire 1985 EPRI report).

527. Consistent with Dr. Rosen's methodology, EPRI recommended holding the utilization factor constant when evaluating the effect of projects such as these on the amount of electricity that a generating unit should be expected to produce. T.T., Sept. 21, 2010, at 77:7-80:20.

528. In addition, the 2004 Sargent & Lundy report recommended that Allegheny use the constant utilization factor assumption when evaluating the effect of projects such as the PSD Projects on electric generation by the unit. DTX 1052 at AE_HQ_00269885 – AE_HQ_00269886 (recommending that Allegheny should calculate the benefits of an "improvement in unit availability" from potential forced-outage rate improvement projects by multiplying the expected change in unit EAF, "EAF_A – EAF_B", by a constant utilization factor, "U", as Dr. Rosen does).

529. With regard to the PSD regulations, Dr. Rosen explained his understanding that the regulations, through a provision known as the "demand growth" exception, require that one exclude expected increases in emissions resulting from expected growth in demand and other unrelated, independent factors. T.T., Sept. 21, 2010, at 73:3-20.

530. The only part of Dr. Rosen's methodology where such demand growth would be reflected is in the utilization factor. T.T., Sept. 21, 2010, at 75:9-19.

531. Dr. Rosen thus held the utilization factor constant as between the pre-project and post-project periods to exclude any expected increases in emissions due to demand growth from his emissions projections, consistent with the regulations. T.T., Sept. 21, 2010, at 75:9-19.74:1-75:8.

532. He determined the pre-project utilization factor – and thus the identical anticipated post-project factor – using Allegheny's own data. T.T., Sept. 21, 2010, at 72:6-15.

iv. Determining the Pre-Project and Expected Post-Project Hours in a Year

533. Dr. Rosen determined the time period, one year, or 8,760 hours, that he used in the pre-project and post project periods. *Id.* at 83:22-84:1.

v. Determining the Pre-Project and Expected Post-Project Unit Capacity

534. Mr. Koppe used his engineering background to evaluate whether the projects would affect the generating capacity of the units, and concluded that there was no reason for any of the PSD Projects to change the generating capacity. T.T., Sept. 20, 2010, at 10:17-11:2, 33:22-34:4; T.T., Sept. 21, 2010, at 84:5-9.

535. Accordingly, based on Mr. Koppe's analysis, Dr. Rosen assumed that the units' megawatt capacities would be the same after the projects as before. He relied on Allegheny's data for the unit capacities for the pre-project periods and then used the same value as the anticipated unit capacities for the post-project period. T.T., Sept. 21, 2010, at 84:5:-9.

vi. Determining the Pre-Project and Expected Post-Project Unit Heat Rate

536. Mr. Koppe used his engineering background to evaluate whether the projects would affect the unit efficiency, *i.e.*, the heat rate of the units. T.T., Sept. 20, 2010, at 10:4-16.

537. Mr. Koppe concluded that there was no reason for any of the PSD Projects to change the unit heat rate. T.T., Sept. 20, 2010, at 33:16-21 (Hatfield's Ferry 2 pendant reheater), *id.* at 33:25-34:4 (Hatfield's Ferry 1 secondary superheater outlet header), *id.* at 51:1-7 (Hatfield's Ferry lower slope projects); T.T., Sept. 21, 2010, at 85:1-4.

538. In particular, with respect to the Armstrong units, although Allegheny expected that the entirety of the work being done on the Armstrong units during the 1994 and 1995 outages would improve the heat rate, Mr. Koppe concluded that Allegheny should not have expected heat rate improvements as a result of the Armstrong PSD Projects, which were limited to replacement and upgrades of certain specific components in the "back end" or convection section, of the boiler. T.T., Sept. 20, 2010, at 110:7-23.

539. Mr. Koppe also concluded that even if some of the heat rate improvement was due to the PSD Projects, that improvement would lead to greater use of the Armstrong units, so that any reductions in emissions due to improved efficiency would be offset by increases in emissions due to increased usage. T.T., Sept. 20, 2010, at 110:23-111:3.

540. Accordingly, Dr. Rosen assumed that the unit heat rates would be the same after the PSD Projects as before the projects: he derived the unit heat rates for the pre-project periods using Allegheny's data and then used the same value as the anticipated heat rate for the post-project period. T.T., Sept. 21, 2010, at 84:15-85:4.

vii. Determining the Pre-Project and Expected Post-Project Coal Heat Content

541. Rosen derived the pre-project heat content of the coal using Allegheny's historical data, and then held the coal heat content constant because there was no evidence that Allegheny expected those pre-project values to change. T.T., Sept. 21, 2010, at 85:5-14.

viii. Determining the Pre-Project and Expected Post-Project Emissions Factors

542. Dr. Rosen calculated the emissions factors for SO_2 and NO_x. T.T., Sept. 21, 2010, at 85:15-17.

543. With regard to SO2, for the pre-project period, Dr. Rosen calculated the emissions factor using a standard reference figure from EPA's AP-42 collection of emissions factors and the sulfur content of the coal at the different units as reported in Allegheny's own data. T.T., Sept. 21, 2010, at 85:22-86:15.

544. He then held the SO_2 emissions factor constant in the post-project period because, under his understanding of the PSD requirements, one can only incorporate anticipated changes

in sulfur content if they are federally enforceable, and there were none. Id. at 86:16-87:20, 179:18-181:25.

545. He also saw no projections indicating that Allegheny expected the sulfur content to change one way or the other. T.T., Sept. 21, 2010, at 87:21-88:5.

546. For NO_x, Dr. Rosen performed two sets of calculations. *Id.* at 88:6-89:8.

547. One NO_x emissions factor incorporated the effect of low-NOx burners, an emission control device which reduces NO_x emissions and which Allegheny had installed at each unit either before or at the same time as the PSD Projects. T.T., Sept. 21, 2010, at 11:4-12:5, 88:6-89:8.

548. The other NO_x emissions factor is higher, because it does not incorporate the NO_x emission-reducing effect of the low-NO_x burners. T.T., Sept. 21, 2010, at 11:4-12:5.

549. Dr. Rosen did one NO_x emissions projection, the "low-NO_x projection," assuming that Allegheny had already installed the low-NO_x burners during the baseline period. T.T., Sept. 21, 2010, at 12:2-5.

550. In this projection, Dr. Rosen held the NO_x emissions factor constant, using the low-NO_x emission factor both before and after the project. T.T., Sept. 21, 2010, at 88:23-89:4.

551. Dr. Rosen did another NO_x emissions projection, the "high-NO_x projection," assuming that low-NO_x burners had not been installed either in the baseline or the post-project period. T.T., Sept. 21, 2010, at 11:20-24.

552. In this projection, Dr. Rosen held the NO_x emissions factor constant, using the high-NO_x emission factor both before and after the project. T.T., Sept. 21, 2010, at 88:25-89:2.

553. Dr. Rosen understood that performing the calculations in either of these two ways would not allow Allegheny to take credit in the PSD emissions projections for the reduction in NO_x emissions due to the low-NO_x burners. T.T., Sept. 21, 2010, at 89:12-89:19.

554. Plaintiffs' counsel asked Dr. Rosen to perform the NO_x emissions projections using these two sets of assumptions. T.T., Sept. 21, 2010, at 88:6-89:11.

555. Thus, for each of the PSD Projects, Dr. Rosen calculated pre- and post-project values for availability factor, utilization factor, hours in a year, unit capacity, heat rate, coal heat content, and emissions factors, and then used those values in his five equations to calculate a pre-project emissions amount and a post-project anticipated emissions amount. T.T., Sept. 21, 2010, at 90:3-94:16; PTX 1997 (calculations for one of the PSD Projects, the Hatfield's Ferry 2 lower slope project).

3. Results of Mr. Koppe's and Dr. Rosen's Analyses for Each PSD Project

a. Armstrong 1 PSD Project

i. Average Generation Baseline

556. From April 1992 through March 1994, boiler components that were replaced in the Armstrong 1 PSD Project caused 706.4 hours of forced outages. PTX 1969; PTX 84.

557. Allegheny should have expected an increase in availability after the Armstrong 1 PSD Project of at least 706.4 hours compared to a baseline period of April 1992 through March 1994. PTX 1969; T.T., Sept. 20, 2010, at 72:13-23, 92:17-98:2.

558. Armstrong 1 was utilized 90 percent of the time it was available during that baseline period. PTX 1969.

559. Armstrong 1 had a capacity factor of 72.7 percent during that baseline period. PTX 1969.

560. Armstrong 1 was in a reserve shutdown for 1.1 days during that baseline period. DTX 1399 at .0020-.0025 (Armstrong 1); T.T., Sept. 23, 2010, at 19:16-20:07, 28:7-12 (explaining that "RS" in GADS means "reserve shutdown).

561. Dr. Rosen reasonably projected that the Armstrong 1 PSD Project would result in an annual SO_2 emissions increase of 798 tons per year compared to the baseline of April 1992 through March 1994. PTX 1969.

562. Allegheny should have projected that the Armstrong 1 PSD project would result in an annual emissions increase of at least 40 tons or more per year of SO_2 from the baseline of April 1992 through March 1994. PTX 1969.

563. Using the high-NO_x assumption, Dr. Rosen reasonably projected that the Armstrong 1 PSD Project would result in an annual NO_x emissions increase of 231 tons per year from the baseline of April 1992 through March 1994. PTX 1974.

564. Using the low-NO_x assumption, Dr. Rosen reasonably projected that the Armstrong 1 PSD Project would result in an annual NO_x emissions increase of 98 tons per year from the baseline of April 1992 through March 1994. PTX 1970.

565. Allegheny should have projected that the Armstrong 1 PSD project would result in an annual emissions increase of at least 40 tons per year or more of NO_x from the baseline of April 1992 through March 1994. PTX 1973

ii. High-Two-of-Five Baseline

566. From October 1990 through September 1992, boiler components that were replaced in the Armstrong 1 PSD Project caused 255.5 hours of forced outages. PTX 84.

567. Allegheny should have expected an increase in availability after the Armstrong 1 PSD Project of at least 255.5 hours compared to a baseline period of October 1990 through September 1992. T.T., Sept. 20, 2010, at 72:13-23; 92:17-98:02.

568. Armstrong 1 was utilized 88.8 percent of the time it was available during that baseline period. PTX 2023.

569. Armstrong 1 had a capacity factor of 75.2 percent during this baseline period. PTX 1969.

570. Armstrong Unit 1 was never in a reserve shutdown during this baseline period. DTX 1399 at .0019-.0021; T.T., Sept. 23, 2010, at 19:16-20:7, 28:7-12.

571. Dr. Rosen reasonably projected that the Armstrong 1 PSD Project would result in an annual SO_2 emissions increase of 286 tons per year compared to the baseline of October 1990 through September 1992. PTX 2023

572. Allegheny should have projected that the Armstrong 1 PSD Project would result in an annual emissions increase of at least 40 tons or more per year of SO_2. PTX 2023

573. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Armstrong PSD Project would result in a NO_x emissions increase of 72 tons per year compared with the baseline of June 1990 through May 1992. PTX 2030.

574. Allegheny should have projected that the Armstrong 1 PSD project would result in an annual emissions increase of at least 40 tons or more per year of NO_x. PTX 2030

575. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Armstrong Unit 1 boiler project would result in a NO_x emissions increase of 30 tons per year compared with the baseline of June 1990 through May 1992. PTX 2024.

b. Armstrong 2 PSD Project

i. Average Generation Baseline

576. From October 1989 through September 1991, components that were replaced in the Armstrong 2 PSD Project caused 753.4 hours of forced outage. PTX 86.

577. Allegheny should have expected an increase in availability after the Armstrong Unit 2 PSD Project of at least 753.4 hours compared to a baseline period of October 1989 through September 1991. T.T., Sept. 20, 2010, at 72:13-23; 92:17-98:02.

578. Armstrong 2 was utilized 87.8 percent of the time it was available during that baseline. PTX 1977.

579. Armstrong 2's capacity factor was 74 percent during that baseline period. PTX 1977.

580. Armstrong 2 was never in a reserve shutdown during that baseline. DTX 1399 at .0043-.0046; T.T., Sept. 23, 2010, at 19:16-20:7, 28:7-12 (explaining that "RS" in GADS means "reserve shutdown").

581. Dr. Rosen reasonably projected that the Armstrong 2 Boiler Project would result in an annual SO_2 emissions increase of 755 tons per year compared to the baseline. PTX 1977.

582. Allegheny should have projected that the Armstrong Unit 2 boiler project would result in an annual emissions increase of at least 40 tons or more per year of SO_2 compared to the baseline of October 1989 through September 1991. PTX 1977.

583. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Armstrong Unit 2 PSD Project would result in an annual NO_x emissions increase of 274 tons per year compared to the baseline. PTX 1982.

584. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Armstrong Unit 2 Boiler Project would result in an annual NO_x emissions increase of 124 tons per year compared to the baseline. PTX 1978.

585. Allegheny should have projected that the Armstrong 2 Boiler Project would result in an annual NO_x emissions increase of at least 40 tons per year compared to the baseline of October 1989 through September 1991. PTX 1982; PTX 1978.

ii. High-Two-of-Five Baselines

586. From December 1990 through November 1992, components that were replaced in the Armstrong 2 PSD Project caused 548.7 hours of forced outage. PTX 86.

587. Allegheny should have expected an increase in availability after the Armstrong 2 PSD Project of at least 548.7 hours compared to a baseline period of December 1990 through November 1992. T.T., Sept. 20, 2010, at 72:13-23, 92:17-98:2..

588. Armstrong 2 was utilized 89.8 percent of the time it was available during the baseline of December 1990 through November 1992. PTX 2035.

589. Armstrong 2's capacity factor was 75.2 percent during that baseline. PTX 2035.

590. Armstrong 2 was never in a reserve shutdown during that baseline. DTX 1399 at .0045-0047; T.T., Sept. 23, 2010, at 19:16-20:7, 28:7-12.

591. Dr. Rosen reasonably projected that the Armstrong 2 PSD Project would result in an annual SO_2 emissions increase of 600 tons per year compared to the baseline. PTX 2035.

592. Allegheny should have projected that the Armstrong 2 PSD Project would result in an annual emissions increase of at least 40 tons or more per year of SO_2 compared to the baseline of December 1990 through November 1992. PTX 2035.

593. From May 1989 through April 1991, components that were replaced in the Armstrong 2 PSD Project caused 596.9 hours of forced outage. PTX 86.

594. Allegheny should have expected an increase in availability after the Armstrong 2 PSD Project of at least 596.9 hours compared to a baseline period of May 1989 through April 1991. T.T., Sept. 20, 2010, at 72:13-23; 92:17-98:2.

595. Armstrong 2 was utilized 87.8 percent of the time it was available during that baseline. PTX 2042.

596. Armstrong Unit 2's capacity factor was 75.3 percent during that baseline. PTX 2042.

597. Armstrong Unit 2 was never in a reserve shutdown during that baseline. DTX 1399 at .0045-0048; T.T., Sept. 23, 2010, at 19:16-20:07, 28:07-12.

598. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Armstrong 2 PSD project would result in a NO_x emissions increase of 215 tons per year compared to the baseline. PTX 2042.

599. Using the low NO assumption, Dr. Rosen reasonably projected that the Armstrong 2 PSD project would result in a NO_x emissions increase of 97 tons per year compared to the baseline of May 1989 through April 1991. PTX 2036.

600. Allegheny should have projected that the Armstrong Unit 2 boiler project would result in a NO_x emissions increase of 40 tons or more year compared to a baseline of May 1989 through April 1991. PTX 2042; PTX 2036.

c. Hatfield's Ferry 1 Lower Slope PSD Project

i. Average Generation Baseline

601. Components that were replaced in the Hatfield 1 lower slope PSD Project caused 327.1 hours of outage between September 1995 and August 1997. PTX 80.

602. Allegheny should have expected an increase in availability after the Hatfield Unit 1 lower slope project of at least 327.1 hours compared to a baseline period of September 1995 through August 1997. T.T., Sept. 20, 2010, at 72:13-23, 92:17-98:2.

603. Hatfield 1 was used to generate electricity 79 per cent of the time it was available between September 1995 and August 1997. PTX 1987.

604. Hatfield 1's average capacity factor was 68 percent between September 1995 and August 1997. PTX 1987.

605. Hatfield 1 was in reserve shutdown an average of 9.2 days per year between September 1995 and August 1997. DTX 1399 at .0079-.0080; T.T., Sept. 23, 2010, at 19:16-20:7, 28:7-12.

606. Dr. Rosen reasonably projected that the Hatfield 1 lower slope project would result in an annual SO_2 emissions increase of 964 tons per year compared to the baseline. PTX 1987.

607. Allegheny should have projected that the Hatfield 1 lower slope project would result in an annual SO_2 emissions increase of at least 40 tons per year compared to the baseline of September 1995 through August 1997. PTX 1987.

608. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 1 lower slope project would result in an annual NO_x emissions increase of 382 tons per year compared to the baseline. PTX 1992.

609. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 1 lower slope project would result in an annual NO_x emissions increase of 143 tons per year compared to the baseline. PTX 1988.

610. Allegheny should have projected that the Hatfield 1 lower slope project would result in a NO_x emissions increase of at least 40 tons per year compared to the baseline of September 1995 through August 1997. PTX 1992; PTX 1988..

ii. High-Two-of-Five Baseline

611. Components that were replaced in the Hatfield 1 lower slope project caused 269.2 hours of outage compared to the period between December 1994 and November 1996.

612. Allegheny should have expected an increase in availability of at least 269.2 hours after the Hatfield 1 lower slope project compared with the period from December 1994 through November 1996. T.T., Sept. 20, 2010, at 72:13-23, 92:17-98:2.

613. Hatfield 1 was used to generate electricity 82.6 percent of the time it was available from December 1994 through November 1996. PTX 2053

614. Hatfield 1's average capacity factor was 73.8 percent between December 1994 and November 1996. PTX 2053

615. Hatfield 1 was in reserve shutdown an average of 7.5 days per year between December 1994 and November 1996. DTX 1399 at .0078-.0080; T.T., Sept. 23, 2010, at 19:16-20:07, 28:07-12.

616. Dr. Rosen reasonably projected that the Hatfield Unit 1 lower slope project would result in an annual SO_2 emissions increase of 896 tons compared to the baseline of December 1994 through November 1996. PTX 2053.

617. Allegheny should have projected that the Hatfield 1 lower slope project would result in an SO_2 emissions increase of at least 40 tons per year compared to the baseline of December 1994 through November 1996. PTX 2053.

618. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 1 lower slope project would result in an annual NO_x emissions increase of 335 tons compared to the baseline of December 1994 though November 1996. PTX 2066.

619. Using the low NOx assumption, Dr. Rosen reasonably projected that the Hatfield 1 lower slope project would result in a n annual NO_x emissions increase of 125 tons as compared to the baseline of December 1994 through November 1996. PTX 2054.

620. Allegheny should have projected that the Hatfield 1 lower slope project would result in a NO_x emissions increase of at least 40 tons per year compared to the baseline of December 1994 through November 1996. PTX 2066; PTX 2054.

d. Hatfield's Ferry 2 Lower Slope PSD Project

i. Average Generation Baseline

621. Components that were replaced in the Hatfield 2 lower slope project caused 143 hours of outage between February 1997 and January 1999. PTX 78

622. Allegheny should have expected an increase in availability of at least 143 hours after the Hatfield 2 lower slope project compared with the baseline period from February 1997 through January 1999. T.T., Sept. 20, 2010, at 72:13-23, 92:17-98:2.

623. Hatfield 2 was used to generate electricity 76 percent of the time it was available from February 1997 through January 1999. PTX 1997.

624. Hatfield 2's average capacity factor was 61.25 percent between February 1997 and January 1999. PTX 1997.

625. Hatfield 2 was in reserve shutdown an average of 6 days per year between February 1997 and January 1999. DTX 1399 at .0043-.0046; T.T., Sept. 23, 2010, at 19:16-20:07, 28:07-12.

626. Dr. Rosen reasonably projected that the Hatfield Unit 2 lower slope project would result in an SO_2 emissions increase of 404 tons per year compared to the baseline. PTX 1997.

627. Allegheny should have projected that the Hatfield Unit 2 lower slope project would result in an annual emissions increase of 40 tons or more per year of SO_2 from the baseline of February 1997 through January 1999. PTX 1997.

628. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 2 lower slope project would result in a NO_x emissions increase of 158 tons per year compared to the baseline of February 1997 through January 1999. PTX 2004

629. Using the low NO_2 assumption, Dr. Rosen reasonably projected that the Hatfield Unit 2 lower slope project would result in a NO_x emissions increase of 64 tons per year compared to the baseline of February 1997 through January 1999. PTX 2015.

630. Allegheny should have projected that the Hatfield Unit 2 lower slope project would result in an annual NO_x emissions increase of 40 tons or more compared to the baseline of February 1997 through January 1999. PTX 2004; PTX 2015.

ii. High-Two-of-Five Baseline

631. Components that were replaced in the Hatfield Unit 2 lower slope project caused 298.8 hours of outage between January 1995 and December 1996. PTX 78.

632. Allegheny should have expected an increase in availability of at least 298.8 hours after the Hatfield Unit 2 lower slope project compared with the baseline period from January 1995 through December 1996. T.T., Sept. 20, 2010, at 72:13-23 (Mr. Koppe).

633. Hatfield 2 was used to generate electricity 80.4 percent of the time it was available from January 1995 through December 1996. PTX 2083.

634. Hatfield 2's average capacity factor was 64.5 percent between January 1995 and December 1996. PTX 2083.

635. Hatfield 2 was in reserve shutdown an average of 14 days per year between January 1995 and December 1996. DTX 1399 at .0120-.0121; T.T., Sept. 23, 2010, at 19:16-20:7, 28:7-12.

636. Dr. Rosen reasonably projected that the Hatfield 2 lower slope project would result in an SO_2 emissions increase of 919 tons per year compared to the baseline. PTX 2083.

637. Allegheny should have projected that the Hatfield Unit 2 lower slope project would result in an annual emissions increase of 40 tons or more per year of SO2 from the baseline of January 1995 through December 1996. PTX 919.

638. From April 1996 through March 1998, components that were replaced in the Hatfield 2 lower slope project caused 97 hours of outage. PTX 78.

639. Using the high NO_x assumption, Dr. Rosen reasonably calculated that the Hatfield 2 lower slope project would result in a NO_x emissions increase of 16 tons per year compared to the baseline period of April 1996 through March 1998. PTX 2012.

640. Using the low NO_x assumption, Dr. Rosen reasonably calculated that the Hatfield 2 lower slope project would result in a NO_x emissions increase of 7 tons per year from the baseline period of April 1996 though March 1998. PTX 2084.

e. Hatfield's Ferry 3 Lower Slope PSD Project

i. Average Generation Baseline

641. Components that were replaced in the Hatfield 3 lower slope project had caused 405.2 hours of outage between October 1992 and September 1994. PTX 82; T.T., Sept. 20, 2010, at 92:17-98:02.

642. Allegheny should have expected an increase in availability after the Hatfield 3 lower slope project of at least 405.2 hours compared to the period of October 1992 though September 1994. T.T., Sept. 20, 2010, at 72:13-23, 92:17-98:02.

643. Hatfield 3 was used to generate electricity 86.8 percent of the time it was available from October 1992 through September 1994. PTX 2005.

644. Hatfield 3's average capacity was 68.7 percent between October 1992 and September 1994. PTX 2005.

645. In the two years between October 1992 and September 1994, Hatfield 3 was in a reserve shutdown an average of 1.2 days per year. DTX 1399 at .0156-.0159; T.T., Sept. 23, 2010, at 19:16-20:7, 28:7-12. (explaining that "RS" in GADS means "reserve shutdown").

646. Dr. Rosen reasonably projected that the Hatfield 3 lower slope project would result in an SO_2 emissions increase of 1,338 tons per year compared to the baseline of October 1992 through September 1994. PTX 2005.

647. Allegheny should have projected that the Hatfield Unit 3 lower slope project would result in an annual emissions increase of 40 tons or more per year of SO_2 from the baseline of October 1992 through September 1994. PTX 2005.

648. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 3 lower slope project would result in a NO_x emission increase of 495 tons per year compared to the baseline of October 1992 through September 1994. PTX 2008.

649. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 3 lower slope project would result in a NO_x emissions increase of 220 tons per year compared to the baseline of October 1992 through September 1994. PTX 2017.

650. Allegheny should have projected that the Hatfield 3 lower slope project would result in a NO_x emissions increase of 40 tons or more per year compared to the baseline of October 1992 through September 1994. PTX 2008; PTX 2017.

ii. High-Two-of-Five Baseline

651. From July 1992 through June 1994, components that were replaced in the Hatfield 3 lower slope project caused 367.2 hours of outage. PTX 82.

652. Allegheny should have expected an increase in availability of at least 367 hours compared to the period July 1992 through June 1994. T.T., Sept. 20, 2010, at 72:13-23.

653. Hatfield 3 was used to generate electricity 87.4 percent of the time it was available from July 1992 through June 1994. PTX 2107.

654. Hatfield 3's average capacity was 70.8 percent between July 1992 and June 1994. PTX 2107.

655. In the two years between July 1992 and June 1994, Hatfield Unit 3 was in a reserve shutdown an average of 1.2 days per year. DTX 1399 at .0155-.0159; T.T., Sept. 23, 2010, at 19:16-20:07, 28:07-12.

656. Dr. Rosen reasonably projected that the Hatfield 3 lower slope project would result in an SO_2 emission increase of 1,244 tons per year compared to the baseline of June 1992 through July 1994. PTX 2107.

657. Allegheny should have projected that the Hatfield 3 lower slope project would result in an annual emissions increase of 40 tons or more per year of SO_2 from the baseline of July 1992 through June 1994. PTX 2107.

658. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 3 lower slope project would result in a NO_x emissions increase of 456 tons per year compared to the baseline period of July 1992 through June 1994. PTX 2114.

659. Using the low NOx assumption, Dr. Rosen reasonably projected that the Hatfield 3 lower slope project would result in a NO_x emissions increase of 203 tons per year compared to the baseline of July 1992 through June 1994. PTX 2108.

660. Allegheny should have projected that the Hatfield 3 lower slope project would result in a NO_x emissions increase of 40 tons or more per year compared to the baseline of July 1992 through June 1994. PTX 2114; PTX 2108.

f. Hatfield's Ferry 2 Pendant Reheater PSD Project

i. Average Generation Baseline

661. Components that were replaced in the Hatfield 2 pendant reheater PSD Project had caused 63 outage hours during the period October 1990 through September 1992. PTX 77.

662. Allegheny should have expected an increase in availability of at least 63 hours after the Hatfield 2 pendant reheater project compared with the period from October 1990 through September 1992. T.T., Sept. 20, 2010, at 72:13-23.

663. Hatfield 2 was used to generate electricity 86.9 percent of the time it was available from October 1990 through September 1992. PTX 1993.

664. Hatfield 2's average capacity factor was 72.2 percent between October 1990 and September 1992. PTX 1993.

665. Hatfield 2 was in reserve shutdown an average of 10 days per year between October 1990 and September 1992. DTX 1399 at .0112-.0116; T.T., Sept. 23, 2010, at 19:16-20:07, 28:07-12 (explaining that "RS" in GADS means "reserve shutdown.").

666. Dr. Rosen reasonably projected that the Hatfield 2 reheater project would result in an SO_2 emissions increase of 224 tons per year compared to the baseline of October 1990 through September 1992. PTX 1993.

667. Allegheny should have projected that the Hatfield 2 reheater project would result in an emissions increase of 40 tons or more per year of SO_2 from the baseline of October 1990 through September 1992. PTX 1993.

668. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 2 reheater project would result in a NO_x emissions increase of 82 tons per year compared to the baseline period of October 1990 through September 1992. PTX 2000..

669. Allegheny should have projected that the Hatfield Unit 2 pendant reheater project would result in a NO_x emissions increase of 40 tons per year or more from the baseline of October 1990 and September 1992. PTX 2000.

670. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 2 reheater project would result in a NO_x emissions increase of 33 tons per year compared to the baseline of October 1990 through September 1992. PTX 2013.

ii. High-Two-of-Five Baseline

671. Components that were replaced in the Hatfield 2 pendant reheater project had caused 63.1 outage hours during the period August 1990 through July 1992. PTX 77.

672. Allegheny should have expected an increase in availability of at least 63.1 hours after the Hatfield 2 pendant reheater project compared with the period from August 1990 through July 1992. T.T., Sept. 20, 2010, at 72:13-23

673. Hatfield Unit 2 was used to generate electricity 87 percent of the time it was available from August 1990 through July 1992. PTX 2071.

674. Hatfield 2's average capacity factor was 75 percent between August 1990 and July 1992. PTX 2071.

675. Hatfield 2 was in a reserve shutdown an average of 10 days per year between August 1990 and July 1992. DTX 1399 at .0112-.0115; T.T., Sept. 23, 2010, at 19:16-20:7, 28:7-12 (explaining that "RS" in GADS means "reserve shutdown").

676. Dr. Rosen reasonably projected that the Hatfield 2 reheater project would result in an SO_2 emissions increase of 231 tons per year compared to the baseline of August 1990 through July 1992. PTX 2071.

677. Allegheny should have projected that the Hatfield 2 reheater project would result in an annual emissions increase of 40 tons or more per year of SO_2 from the baseline of August 1990 through July 1992. PTX 2071.

678. Components that were replaced in the Hatfield 2 reheater project caused no forced outages in the baseline of May 1989 through April 1991. PTX 77.

679. Dr. Rosen reasonably projected that the Hatfield 2 reheater project would cause no NO_x emissions increase in the baseline of May 1989 through April 1991. PTX 2072, 2090.

g. Hatfield's Ferry 1 Secondary Superheater Outlet Header PSD Project

i. Average Generation Baseline

680. Problems with the SSOHs that were replaced in the Hatfield 1 SSOH project caused 154.5 hours of outage between September 1995 and August 1997. PTX 81.

681. Allegheny should have expected an increase in availability of at least 154.5 hours after the Hatfield 1 SSOH project compared with the period from September 1995 through August 1997. T.T., Sept. 20, 2010, at 72:13-23.

682. Hatfield 1 was used to generate electricity 79 percent of the time it was available from September 1995 through August 1997. PTX 1985.

683. Hatfield 1's average capacity factor was 68 percent between September 1995 and August 1997. PTX 1985.

684. Hatfield 1 was in reserve shutdown an average of 9.8 days per year between September 1995 and August 1997. DTX 1399 at .0079-.0080; T.T., Sept. 23, 2010, at 19:16-20:07, 28:07-12 (explaining that "RS" in GADS means "reserve shutdown).

685. Dr. Rosen reasonably projected that the Hatfield 1 SSOH project would result in an SO_2 emissions increase of 455 tons per year compared to the baseline of September 1995 through August 1997. PTX 1985.

686. Allegheny should have projected that the Hatfield 1 SSOH project would result in an emissions increase of 40 tons or more per year of SO_2 compared to the baseline of September 1995 through August 1997. PTX 1985.

687. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 1 SSOH project would result in a NO_x emissions increase of 180 tons per year compared to the baseline of September 1995 through August 1997. PTX 1990.

688. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 1 SSOH project would result in a NO_x emissions increase of 68 tons per year compared to the baseline of September 1995 through August 1997. PTX 1986.

689. Allegheny should have projected that the Hatfield 1 SSOH project would result in a NO_x emissions increase of 40 tons or more per year compared to the baseline of September 1995 through August 1997. PTX 1990; PTX 1986.

ii. High-Two-of-Five Baseline

690. From December 1994 through November 1996, components that were replaced in the Hatfield 1 SSOH project caused 66.5 hours of outage. PTX 81.

691. Allegheny should have expected an increase in availability of at least 66 hours after the Hatfield 1 SSOH project compared with the period from December 1994 through November 1996. T.T., Sept. 20, 2010, at 72:13-23.

692. Hatfield 1 was used to generate electricity 82.6 percent of the time it was available from December 1994 through November 1996. PTX 2047.

693. Hatfield 1's average capacity factor was 73.8 percent between December 1994 and November 1997. PTX 2047.

694. Hatfield 1 was in reserve shutdown an average of 24 days per year between December 1994 and November 1996. DTX 1399 at .0078-.0080; T.T., Sept. 23, 2010, at 19:16-20:7, 28:7-12.

695. Dr. Rosen reasonably projected that the Hatfield 1 SSOH project would result in an SO_2 emissions increase of 221 tons per year compared to the baseline of December 1994 through November 1996. PTX 2047.

696. Allegheny should have projected that the Hatfield 1 SSOH project would result in an SO2 emissions increase of 40 tons or more per year compared to the baseline of September 1995 through August 1997. PTX 2047.

697. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Hatfield 1 SSOH project would result in a NO_x emissions increase of 83 tons per year compared to the baseline of December 1994 through November 1996. PTX 2060.

698. Allegheny should have projected that the Hatfield 1 SSOH project would result in a NO_x emissions increase of 40 tons or more per year compared to the baseline of December 1994 through November 1996. PTX 2060.

699. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Hatfield Unit 1 SSOH project would result in a NO_x emissions increase of 31 tons per year compared to the baseline of December 1994 through November 1996. PTX 2048.

h. Mitchell 3 Lower Slope PSD Project

i. Average Generation Baseline

700. Dr. Rosen reasonably projected that the Mitchell Unit 3 lower slope project would result in an SO_2 emissions increase of 11 tons per year compared to the baseline of June 1992 through May 1994. PTX 2009.

701. Components that were replaced in the Mitchell 3 lower slope project had caused 194.1 outage hours during the period June 1992 through May 1994. PTX 83.

702. Allegheny should have expected an increase in availability of at least 194.1 hours after the Mitchell 3 lower slope project compared to the period June 1992 through May 1994. T.T., Sept. 20, 2010, at 72:13-23.

703. Mitchell 3 was used to generate electricity 68.7 percent of the time it was available from June 1992 through May 1994. PTX 2012.

704. Mitchell 3's average capacity factor was 60.27 percent between June 1992 and May 1994. PTX 2012.

705. Mitchell 3 was in reserve shutdown an average of 16 days per year between June 1992 and May 1994. DTX 1399 at .0120-.0213; T.T., Sept. 23, 2010, at 19:16-20:07, 28:07-12.

706. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Mitchell 3 lower slope project would result in an annual NO_x emissions increase of 57 tons per year from the baseline period of June 1992 through May 1994. PTX 2012.

707. Allegheny should have projected that the Mitchell 3 lower slope project would result in an annual emissions increase of 40 tons per year or more of NO_x from the baseline of June 1992 through May 1994. PTX 2012.

708. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Mitchell Unit 3 lower slope project would result in an annual NO_x emissions increase of 37 tons per year from the baseline period of June 1992 through May 1994. PTX 2010.

ii. High-Two-of-Five Baseline

709. Dr. Rosen reasonably projected that the Mitchell 3 lower slope project would result in an SO_2 emissions increase of 8 tons per year from the baseline of September 1992 and August 1994. PTX 2125.

710. Components that were replaced in the Mitchell 3 lower slope project had caused 162.65 outage hours during the period from January 1990 through December 1991. PTX 83.

711. Allegheny should have expected an increase in availability of at least 162.65 hours after the Mitchell 3 lower slope project compared to the period from January 1990 through December 1991. T.T., Sept. 20, 2010, at 72:13-23.

712. Mitchell 3 was used to generate electricity 69.8 percent of the time it was available from January 1990 through December 1991. PTX 2126.

713. Mitchell 3's average capacity factor was 61.7 percent between January 1990 through December 1991. PTX 2126.

714. Mitchell 3 was in reserve shutdown an average of 8.35 days per year between January 1990 through December 1991. DTX 1399 at .0207-.0210; T.T., Sept. 23, 2010, at 19:16-20:07, 28:07-12 (explaining that "RS" in GADS means "reserve shutdown").

715. Using the high NO_x assumption, Dr. Rosen reasonably projected that the Mitchell 3 lower slope project would result in an annual NO_x emissions increase of 48 tons per year compared to the baseline period of January 1990 through December 1991. PTX 2126.

716. Allegheny should have projected that the Mitchell 3 lower slope project would result in an annual NO_x emissions increase of at least 40 tons per year or more of NO_x from the baseline of January 1990 through December 1991. PTX 2126.

717. Using the low NO_x assumption, Dr. Rosen reasonably projected that the Mitchell 3 lower slope project would result in an annual NO_x emissions increase of 31 tons per year from the baseline of January 1990 through December 1991. PTX 2120.

i. Projects for Which Dr. Rosen Did Not Project a 40 Ton Per Year Emissions Increase

718. When Mr. Koppe analyzed the GADS data for the replacement of the secondary superheater outlet headers at Hatfield 2, he could not completely document that any of the outages in the five years preceding the project were caused by those outlet headers. PTX 79.

719. Dr. Rosen therefore did not project any emissions increase resulting from the Hatfield Unit 2 secondary superheater outlet header project. T.T., Sept. 21, 2010, at 15:25-16:4..

720. Dr. Rosen projected an 11 ton per year SO_2 emissions increase resulting from the Mitchell 3 lower slope project. T.T., Sept. 21, 2010, at 16:5-6.

721. Dr. Rosen projected a 31 ton per year NO_x emissions increase resulting from the Mitchell Unit 3 lower slope project compared to the high two-of-five baseline and using the low-NO_x to low-NO_x calculation. PTX 2120.

722. Dr. Rosen projected no SO_2 or NO_x emissions increases resulting from the Hatfield 2 pendant reheater project compared to the high two-of-five baseline. PTX 2072; PTX 2090.

723. Dr. Rosen projected a NO_x emissions increase of 31 tons per year resulting from the Hatfield 1 secondary superheater outlet header project when compared to the high two-of-five baseline and using the low-NO_x to low-NO_x methodology. PTX 2048

724. Dr. Rosen projected a NO_x emissions increase of 16 and 7 tons per year resulting from the Hatfield 2 lower slope project compared to the high two-of-five baseline and using the high NO_x to high NO_x and low-NO_x to low-NO_x methodologies respectively. PTX 2012; PTX 2084.

4. Alternative NO_x Emissions Projections Using Dr. Rosen's Results

725. Dr. Rosen intentionally used the high-NO_x assumptions for one set of NO_x calculations, and the low-NO_x assumptions for another set of NO_x calculations, at the request of counsel, on the understanding that doing so would not allow Allegheny to take credit in the

PSD emissions calculations for the emissions reductions due to the low-NO_x burners. T.T., Sept. 21, 2010, at 88:18-89:19.

a. Armstrong 1 PSD Project

726. Dr. Rosen calculated the pre-project emissions amount for the Armstrong 1 PSD Project, using the high-NO_x emissions factor, as 4,973 tons per year. PTX 1974.

727. Dr. Rosen calculated the post-project projection for the Armstrong 1 PSD Project, using the low-NO_x emissions factor, as 2,207 tons per year. PTX 1970.

728. The difference between Dr. Rosen's low-NO_x post-project amount and his high-NO_x pre-project amount for the Armstrong 1 PSD Project is -2,766 tons per year. PTX 1974; PTX 1970.

b. Armstrong 2 PSD Project

729. Dr. Rosen calculated the pre-project emissions amount for the Armstrong 2 PSD Project, using the high-NO_x emissions factor, as 5,782 tons per year. PTX 1982.

730. Dr. Rosen calculated the post-project projection for the Armstrong 2 PSD Project, using the low-NO_x emissions factor, as 2,741 tons per year. PTX 1978.

731. The difference between Dr. Rosen's low-NO_x post-project amount and his high-NO_x pre-project amount for the Armstrong 2 PSD Project is -3,041 tons per year. PTX 1982; PTX 1978.

5. Comparison Emissions Calculations by Allegheny

732. In a 1995 report regarding Allegheny's NO_x compliance strategies, Allegheny reviewed aggregate NO_x emission projections from the Armstrong, Hatfield's Ferry, Mitchell 3 and R. Paul Smith power stations. PTX 1871 at AE_MIT00038651, AE_MIT00038652;

733. The Smith plant is a small coal-fired generating unit located in western Maryland. PTX 20 at 13 (noting that Smith plant has a total capacity of 114 MW compared with 352 MW for Armstrong, 1,660 MW for Hatfield's Ferry, and 284 MW for Mitchell).

734. In the 1995 report, Allegheny compared two sets of NO_x emissions forecasts for this group of plants against actual results. PTX 1871 at AE_MIT00038651, AE_MIT00038652.

735. For one set of forecasts, the projected amounts always exceeded the actual results. PTX 1871 at AE_MIT00038651.

736. In percentage terms, the largest difference between Allegheny's projections and the actual results was 18 percent, in the 1991 figures on the second set of forecasts. PTX 1871 at AE_MIT00038652 (18 percent difference calculated by subtracting the 1991 projection of 12,318 tons from the actual result of 15,022 tons, and then dividing that number by the actual result of 15,022 tons).

737. If one aggregates Dr. Rosen's SO_2 emissions projections for the Armstrong PSD Projects, the Hatfield's Ferry lower slope PSD Projects, and Mitchell 3, the difference between his projections and the actual results was 3.2 percent, as the following table shows:

SO_2 emissions (in tons per year)

Project	Dr. Rosen's Post-Project Projected Emissions	Post-Project Actual Emissions
Armstrong 1: Radiant Side and Convection Side	18,006	15,878
Armstrong 2: Radiant Side and Convection Side	16,693	16,245
Hatfield 1: Lower Slope	48,881	48,099
Hatfield 2: Lower Slope	46,171	54,710
Hatfield 3: Lower Slope	52,680	41,825
Mitchell 3: Lower Slope	948	781
Total	**183,379**	**177,718**
Difference Between Projected and Actual		+5,661
Percentage Difference Between Projected and Actual		**+3.2%**

The source for the figures in the second column is PTX 2179(d); the source for the figures in the third column is Docket Item 431 ¶ 12.

738. If one aggregates Dr. Rosen's NO_x emissions projections, using the low-NO_x assumption, for the Armstrong PSD Projects, the Hatfield's Ferry lower slope PSD Projects, and Mitchell 3, the difference between his projections and the actual results was 10.5 percent for NO_x, as the following table shows:

NO_x emission (in tons per year)

Project	Dr. Rosen's Post-Project Expected Emissions (Low-NO_x)	Post-Project Actual Emissions
Armstrong 1: Radiant Side and Convection Side	2,207	2,054
Armstrong 2: Radiant Side and Convection Side	2,741	2,886
Hatfield 1: Lower Slope	7,327	6,931
Hatfield 2: Lower Slope	7,335	7,396
Hatfield 3: Lower Slope	8,661	6,721
Mitchell 3: Lower Slope	3,149	2,450
Total	**31,420**	**28,438**
Difference Between Projected and Actual		+2,982
Percentage Difference Between Projected and Actual		**+10.5%**

The source for the figures in the second column is PTX 2179(d); the source for the figures in the third column is Docket Item 431 ¶ 12.

6. Calculation of the Net Expected Increase in Electricity Demand After Removing Expected PURPA Imports and Load Modification "Goals"

739. In April 1995, Allegheny filed its annual report to the PA PUC that provided Allegheny's (1) forecasts of future total demand for Allegheny's system, (2) forecasts of future PURPA imports into the system, and (3) future load management goals.[3] *See* PTX 1223 at AE_DUN_00381068, *id.* at AE_DUN_00381094, *id.* at AE_DUN_00381113.

740. Allegheny at that time expected electricity demand to grow significantly each year until at least 2001, even after reducing the expected overall growth by the amount of the expected PURPA imports and load management goals, as the following table shows:

Year	Expected Total Energy Demand: Base Scenario (GWH)	Expected PURPA Imports (GWH)	Load Management Goal (GWH)	Expected Net Energy Demand (Total Energy Demand minus PURPA Imports minus Load Management Goal (GWH)	Growth in Expected Net Energy Demand (GWH)
1995	19,184.2	1,015	274	17,895.2	
1996	19,755.1	1,018	285.2	18,451.9	556.7
1997	20,245.6	1,285	298.8	18,661.8	209.9
1998	20,695.2	1,541	314.7	18,839.5	177.7
1999	20,984.7	1,541	333.5	19,110.2	270.7
2000	21,290.4	1,545	352.4	19,393.0	282.8
2001	21,468.8	1,541	371.3	19,556.5	163.5

The source for the data in the second column is PTX 1223 at AE_DUN_00381069; the source for the data in the third column is PTX 1223 at AE_DUN_00381094; the source for the data in

[3] All of the figures referenced in the following paragraphs relate to Allegheny's West Penn Company service area, principally in Pennsylvania, rather than the total Allegheny service area. PTX 1223.

the fourth column is PTX 1223 at AE_DUN_00381113; the figures in the fifth column are calculated by taking the figure in the second column minus the figure in the third column and the figure in the fourth column; the figures in the sixth column are calculated by taking the figure in the fifth column for a given year and subtracting from it the figure in the fifth column for the preceding year, *e.g.*, the growth in expected net energy demand for 1996 is equal to the expected net energy demand for 1996 (18,451.9) minus the expected net energy demand for 1995 (17,895.2).

D. Allegheny's Failure to Perform Emissions Projections Consistent with the PSD Regulations

741. Allegheny did not do any formal projection of whether the Hatfield 1 lower slope project would increase emissions. D.T. (Clark Colby 30(b)(6) witness on Hatfield projects), July 27, 2010, at 54:25-56:5.

742. Allegheny did not do any formal projection of whether the Hatfield 2 lower slope project would increase emissions. D.T. (Clark Colby 30(b)(6) witness on Hatfield projects), July 27, 2007, at 71:1-12.

743. Allegheny did not do any formal projection of whether the Hatfield 3 lower slope project would increase emissions. D.T. (Clark Colby 30(b)(6) witness on Hatfield projects), July 27, 2007, at 74:20-75:5.

744. Allegheny did not do any formal projection of whether the Hatfield 2 pendant reheater project would increase emissions. D.T. (Clark Colby 30(b)(6) witness on Hatfield projects), July 27, 2007, at 68:18-69:5.

745. Allegheny did not do any formal projection of whether the Hatfield 1secondary superheater outlet header project would increase emissions. D.T. (Clark Colby 30(b)(6) witness on Hatfield projects), July 27, 2007, at 66:4-16.

746. Allegheny did not do any formal projection of whether the Mitchell 3 lower slope project would increase emissions. T.T., Sept. 23, 2010, at 135:18-21 (testimony of Dale Evans, an Allegheny employee who worked on the Mitchell PSD Project).

747. In 1993, an Allegheny maintenance engineer at the Armstrong power station named Jeffrey Mooney attempted to evaluate for PSD purposes whether the totality of the work at Armstrong 2 would have an effect on its annual emissions. PTX 177.

748. Mr. Mooney determined that SO_2 emissions could increase because Allegheny expected the availability of the Armstrong units to increase. PTX 177 at AE_ARM00132856.

749. Mr. Mooney concluded that heat rate improvements due to the projects would reduce emissions by approximately the same amount as the increased generation due to increased availability would increase emissions. PTX 177 at AE_ARM00132856.

750. In his analysis, Mr. Mooney computed the Armstrong units' past availability by relying on annual outage data for both units from the preceding five years and eliminating from his calculations, the two years with the longest outages. T.T., Sept. 20, 2010, at 104:13-105:23; PTX 178 at AE_ARM00132602.

751. By eliminating the two past years with the longest outages, Mr. Mooney calculated the Armstrong units' past availability as greater than it actually was and the increase in availability from the projects as smaller than should have been expected. T.T., Sept. 20, 2010, at 105:24-106:10.

752. Mr. Koppe redid Mr. Mooney's calculation but without discarding the years with the longest outages, and concluded that the availability increase from the projects is 7.7 percent, not 4.6 percent. T.T., Sept.20, 2010, at 105:6-106:10.

753. Mr. Koppe corrected the availability increase from 4.6 to 7.7 percent, and projected that SO_2 emissions would increase by 475 tons per year. T.T., Sept. 20, 2010, at 109:4-22.

754. Mr. Mooney also overestimated the expected efficiency increase due to a lower heat rate. T.T., Sept. 20, 2010, at 107:9-109:3 (Mr. Koppe).

755. Using Allegheny's actual efficiency numbers for the previous five years, Mr. Koppe concluded that efficiency increased by only 3.77 percent, and not 4.5 percent. T.T., Sept. 20, 2010, at 108:14-109:3.

756. When he corrected for both the availability and efficiency errors, Mr. Koppe calculated an expected SO_2 emissions increase of 650 tons per year. T.T., Sept. 20, 2010, at 109:18-110:5.

E. Allegheny's Failure to Obtain PSD Preconstruction Permits and to Comply with PSD Emissions Limitations

1. Armstrong 1 PSD Project

757. Allegheny did not apply for or obtain a preconstruction permit for the Armstrong 1 PSD Project. PTX 2 ¶¶ 134, 144, 146.

758. Allegheny did not operate Armstrong 1 subject to Best Available Control Technology ("BACT") emissions limitations after completion of the Armstrong 1 PSD Project. PTX 2 ¶¶ 136, 148.

2. Armstrong 2 PSD Project

759. Allegheny did not apply for or obtain a preconstruction permit for the Armstrong 2 PSD Project. PTX 2 ¶¶ 198, 208, 210.

760. Allegheny did not operate Armstrong 2 subject to BACT emissions limitations after completion of the Armstrong 2 PSD Project. PTX 2 ¶¶ 200, 212.

3. Hatfield 1 Lower Slope PSD Project

761. Allegheny did not apply for or obtain a PSD preconstruction permit for the Hatfield 1 lower slope PSD Project. PTX 2 ¶¶ 287, 297, 299.

762. Allegheny did not operate Hatfield 1 subject to BACT emissions limitations after completion of the Hatfield 1 lower slope PSD Project. PTX 2 ¶¶ 289, 301.

4. Hatfield 2 Lower Slope PSD Project

763. Allegheny did not apply for or obtain a PSD preconstruction permit for the Hatfield 2 lower slope PSD Project. PTX 2 ¶¶ 309, 319, 321.

764. Allegheny did not operate Hatfield 2 subject to BACT emissions limitations after completion of the Hatfield 2 lower slope PSD Project. PTX 2 ¶¶ 311, 323.

5. Hatfield 3 Lower Slope PSD Project

765. Allegheny did not apply for or obtain a PSD preconstruction permit for the Hatfield 3 lower slope PSD Project. PTX 2 ¶¶ 331, 341, 343.

766. Allegheny did not operate Hatfield 3 subject to BACT emissions limitations after completion of the Hatfield 1 lower slope PSD Project. PTX 2 ¶¶ 333, 345.

6. Hatfield 2 Pendant Reheater PSD Project

767. Allegheny did not apply for or obtain a PSD preconstruction permit for the Hatfield 2 pendant reheater PSD Project. PTX 2 ¶¶ 309, 319, 321.

768. Allegheny did not operate Hatfield 2 subject to BACT emissions limitations after completion of the Hatfield 2 pendant reheater PSD Project. PTX 2 ¶¶ 311, 323.

7. Hatfield 1 Secondary Superheater Outlet Header PSD Project

769. Allegheny did not apply for or obtain a PSD preconstruction permit for the Hatfield 1 SSOH PSD Project. PTX 2 ¶¶ 287, 297, 299.

770. Allegheny did not operate Hatfield 1 subject to BACT emissions limitations after completion of the Hatfield 1 SSOH PSD Project. PTX 2 ¶¶ 289, 301.

8. Mitchell 3 PSD Project

771. Allegheny did not apply for or obtain a PSD preconstruction permit for the Mitchell 3 lower slope PSD Project. PTX 2 ¶¶ 379, 389, 391.

772. Allegheny did not operate Mitchell 3 subject to BACT emissions limitations for NO_x after completion of the Mitchell 3 lower slope project. PTX 2 ¶¶ 381, 393.

VII. ADDITIONAL FACTS RELEVANT TO THE NONATTAINMENT NSR CLAIMS

773. The projects relevant to PA DEP's nonattainment NSR claims are the Armstrong 1 and 2 Reconstruction Projects, because they constitute "new sources" under Pennsylvania law. 25 Pa. Code § 121.1.

A. Dr. Rosen's Nonattainment NSR Emissions Calculations – His General Approach

774. Dr. Rosen did a set of emissions calculations for the Armstrong Reconstruction Projects known as "actual to potential to emit" calculations. T.T., Sept. 21, 2010, at 105:18-106:4.

775. In this type of calculation he calculated the difference between (1) the unit's emissions in the period before the project and (2) the unit's potential to emit in the period after the project. T.T., Sept. 21, 2010, at 106:2-4.

776. For the pre-project period, he calculated emissions in the same way as he did for the "actual to projected future actual" PSD calculations he performed. T.T., Sept. 21, 2010, at 106:8-15.

777. For the post-project period, he calculated the unit's potential to emit by using his same five-equation methodology but assuming that the unit was running at full capacity for the entire year. T.T., Sept. 21, 2010, at 106:5-7.

778. More specifically, that meant that for the post-project period he assumed that both the availability factor and the utilization factor were 100 percent. T.T., Sept. 21, 2010, at 106:19-107:10.

B. Results of Dr. Rosen's Emissions Analyses for Each Armstrong Reconstruction (Nonattainment NSR) Project

1. Armstrong 1

779. Dr. Rosen reasonably projected that the Armstrong 1 Reconstruction Project would result in an annual SO_2 emissions increase of 6,449 tons per year under the potential-to-emit approach. PTX 1971.

780. Allegheny should have projected that the Armstrong 1 Reconstruction Project would result in an annual SO_2 emissions increase of at least 40 tons per year under the potential-to-emit approach. PTX 1971.

781. Dr. Rosen reasonably projected that the Armstrong 1 Reconstruction Project would result in an annual NO_x emissions increase of 1,864 tons per year under the potential-to-emit approach and the high-NO_x assumption. PTX 1976.

782. Dr. Rosen reasonably projected that the Armstrong 1 Reconstruction Project would result in an annual NO_x emissions increase of 790 tons per year under the potential-to-emit approach and the low-NO_x assumption. PTX 1972.

783. Allegheny should have projected that the Armstrong 1 Reconstruction Project would result in an annual NO_x emissions increase of at least 40 tons per year under the potential-to-emit approach. PTX 1976, PTX 1972.

2. Armstrong 2

784. Dr. Rosen reasonably projected that the Armstrong 2 Reconstruction Project would result in an annual SO_2 emissions increase of 5,579 tons per year under the potential-to-emit approach. PTX 1979.

785. Allegheny should have projected that the Armstrong 2 Reconstruction Project would result in an annual SO_2 emissions increase of at least 40 tons per year under the potential-to-emit approach. PTX 1979.

786. Dr. Rosen reasonably projected that the Armstrong 2 Reconstruction Project would result in an annual NO_x emissions increase of 2,024 tons per year under the potential-to-emit approach and the high-NO_x assumption. PTX 1984.

787. Dr. Rosen reasonably projected that the Armstrong 2 Reconstruction Project would result in an annual NO_x emissions increase of 916 tons per year under the potential-to-emit approach and the low-NO_x assumption. PTX1980.

788. Allegheny should have projected that the Armstrong 2 Reconstruction Project would result in an annual NO_x emissions increase of at least 40 tons per year under the potential-to-emit approach. PTX 1984; PTX1980.

C. Allegheny's Failure to Obtain Nonattainment NSR Preconstruction Permits and to Comply with Nonattainment NSR Emissions Limitations

789. Allegheny did not apply for or obtain a nonattainment NSR permit or plan approval for the Armstrong 1 Reconstruction Project. PTX 2 ¶ 158, 162.

790. Allegheny did not operate Armstrong 1 subject to LAER emissions limitations for SO_2 or NO_x after completion of the Armstrong 1 Reconstruction Project. PTX 2 ¶ 160.

791. Allegheny did not apply for or obtain a nonattainment NSR permit or plan approval for the Armstrong 2 Reconstruction Project. PTX 2 ¶ 221, 223.

792. Allegheny did not operate Armstrong 2 subject to LAER emissions limitations for SO_2 or NO_x after completion of the Armstrong 2 Reconstruction Project. PTX 2 ¶ 225.

VIII. ALLEGHENY'S TITLE IV AND RACT COMPLIANCE EFFORTS

A. Allegheny's Title IV Compliance

793. In early 1991, Allegheny decided on its strategy to comply with the SO_2 reduction requirements of Title IV of the 1990 Clean Air Act amendments, and set out that strategy in a memorandum that was cleared for public release. DTX 1629 at AE_HF00080544.

794. The compliance strategy Allegheny chose was to install flue gas desulfurization equipment, or "scrubbers," on the generating units at its Harrison power station in West Virginia. T.T., Sept. 22, 2010, at 162:20-163:13; DTX 1629 at AE_HF00080546.

795. According to Allegheny witnesses, Allegheny anticipated that the installation of the scrubbers at the Harrison power station made the Harrison generating units less expensive to run, taking into account the cost of the emissions allowances under the Title IV program, so that Allegheny expected to use the Harrison units more and the remaining Allegheny units less. *See*, *e.g.*, T.T., Sept. 22, 2010, at 165:25-167:11 (Mr. Skrgic); T.T., Sept. 23, 2010, at 186:10-187:8 (Mr. Colby).

796. At the same time, Allegheny rejected a switch to low-sulfur coal for many reasons: it would have been more costly, would have harmed local economies, would have introduced issues of coal and transportation price volatility, and would have precluded flexibility in complying with future Title IV requirements. DTX 1629 at AE_HF00080549-AE_HF00080550, AE_HF00080551; T.T., Sept. 22, 2010, at 179:1-180:9 (Mr. Skrgic).

797. Allegheny's capital work orders for the PSD Projects do not reference Title IV or SO_2 emissions reductions as part of the nature, extent or purpose of the projects. *See*, *e.g.*,

PTX 1924 (Armstrong 1); PTX 1929 (Armstrong 2); PTX 1930 (Hatfield's Ferry 1 secondary superheater outlet header); PTX 1931 (Hatfield's Ferry 1 lower slope panel); PTX 1932 (Hatfield's Ferry 2 pendant reheater); PTX 1933 (Hatfield's Ferry 2 lower slope panel); PTX 1934 (Hatfield's Ferry 3 lower slope panel); PTX 1935 (Mitchell 3).

798. There was no relationship between the PSD Projects and Allegheny's Title IV compliance measures. *See* Plaintiffs' Findings of Fact 791-795 above.

B. Allegheny's RACT Compliance

799. To comply with the RACT requirements for NO_x emissions that Congress enacted in the 1990 Clean Air Act Amendments, Allegheny decided to install special burners, known as "low-NO_x burners," at its Armstrong, Hatfield's Ferry and Mitchell 3 units. PTX 1919 at AE_DUN_00047426 – AE_DUN_00047427; PTX 260 *passim* (Armstrong); PTX 1084 at AE_DUN_00047441-AE_DUN_00047442; PTX 1085 (Hatfield's Ferry 3); T.T., Sept. 23, 2010, at 133:12-20 (Mitchell 3).

800. Allegheny installed low-NO_x burners at Armstrong 1 during an outage that ran from February 27, 1995 through October 23, 1995. PTX 1919 at AE_DUN_00047429; PTX 69 at 18.

801. Allegheny installed low-NO_x burners at Armstrong 2 during an outage that ran from April 26, 1994 through December 21, 1994. PTX 1919 at AE_DUN_00047429; PTX 69 at 42.

802. Allegheny installed low-NO_x burners at Hatfield 1 during an outage that ran from October 2, 1994 through November 23, 1994. Docket Item 430 ¶ 23.

803. Allegheny installed low-NO_x burners at Hatfield 2 during an outage that ran from September 25, 1993 through December 3, 1993. Docket Item 430 ¶ 24.

804. Allegheny installed low-NO_x burners at Hatfield 3 during an outage that ran from February 25, 1995 through May 8, 1995. Docket Item 430 ¶ 25.

805. Allegheny installed low-NO_x burners at Mitchell 3 during an outage that ran from October 7, 1994 through December 30, 1994. Docket Item 430 ¶ 66.

806. Low-NO_x burners typically result in NO_x emissions reductions on the order of 27 to 68 percent.

807. According to Allegheny, installation of low-NO_x burners at Hatfield 2 reduced emissions by approximately 57 percent, from 1.28 lb./mmBTU to 0.52 lb./mmBTU. PTX 1920 at AE_DUN_00047451.

808. With regard to Hatfield, Allegheny's capital work orders for the PSD Projects at those three units do not reference Clean Air Act compliance or NO_x emissions reductions as part of the nature, extent or purpose of the projects. PTX 1930 (Hatfield's Ferry 1 secondary superheater outlet header); PTX 1931 (Hatfield's Ferry 1 lower slope panel); PTX 1932 (Hatfield's Ferry 2 pendant reheater); PTX 1933 (Hatfield's Ferry 2 lower slope panel); PTX 1934 (Hatfield's Ferry 3 lower slope panel).

809. Similarly, the capital work orders for the RACT projects for Hatfield's Ferry make no reference to the PSD Projects. *See, e.g.*, PTX 1085 (Hatfield's Ferry 3).

810. In fact, for four of the PSD Projects – the secondary superheater project at Hatfield's Ferry 1 and the lower slope projects at all three Hatfield's Ferry units – the installation of the low-NO_x burners took place a year or more before the PSD Project. *Compare* Docket Item 430 ¶¶ 23, 24, 25 (installation of low-NO_x burners at Hatfield's Ferry 1 in fall 1994, Hatfield's Ferry 2 in fall 1993, and Hatfield's Ferry 3 in spring 1995) *with* Docket

Item 430 ¶¶ 27, 33, 49, 57, (PSD Projects at Hatfield's Ferry 1 in fall 1997, at Hatfield's Ferry 2 in fall 1999, and at Hatfield's Ferry 3 in fall 1996).

811. There was no relationship between the PSD Projects and the low-NO_x burner installations at Hatfield. *See* materials cited in Plaintiffs Findings of Fact 800-801, 806-808 above.

812. With regard to Mitchell 3, Allegheny's capital work order for the PSD Project at that unit does not reference Clean Air Act compliance or NO_x emissions reductions as part of the nature, extent or purpose of the projects. *See* PTX 1935.

813. Similarly, the capital work orders for the RACT projects for Mitchell 3 makes no reference to the PSD Projects. *See, e.g.,* PTX 1086.

814. There was no relationship between the Mitchell 3 PSD Project and the low-NO_x burner installation at that unit. *See* Plaintiffs' Findings of Fact 810-811 above.

815. As for the Armstrong units, the original Armstrong work orders for the large-scale boiler rehabilitation projects did not even mention the low-NO_x burner installation, as Allegheny had intended to perform the Armstrong boiler work regardless of the 1990 Amendments. PTX 1926.

816. Later versions of Allegheny's capital work orders for the PSD Projects explicitly distinguish and exclude the work relating to the low-NO_x burner installation from the work constituting the PSD Projects, i.e., replacement of the convection superheater, reheater , economizer and other components. *See* PTX 1924 at R-3 09513 (transferring work from the "boiler project" work order to the low-NO_x burner work order to "accurately segregate the components . . . required . . . to meet NO_x compliance as mandated by the 1990 Clean Air Act Amendments")

817. The capital work orders for the Armstrong low-NO_x burner projects do not contain the PSD Project work *See, e.g.*, PTX 1925 at R-3 10200.

818. There was no relationship between the Armstrong 1 and 2 PSD Projects and the Armstrong 1 and 2 low-NO_x burner installations. *See* Plaintiffs' Findings of Fact 813-815 above.

IX. ALLEGHENY TITLE V APPLICATIONS AND PERMITS

A. Armstrong

819. Allegheny submitted a Title V permit application to PA DEP for the Armstrong power station in July 1995. PTX 1210.

820. The Armstrong Title V permit application did not address the Armstrong Reconstruction or PSD Projects or identify as applicable requirements any BACT, NSPS, nonattainment NSR or BAT emissions limitations that would have been required as a result of those projects. PTX 1210 *passim*.

821. Allegheny certified that its Armstrong Title V permit application was true, accurate and complete. PTX 1210 at AE_HQ_00136678.

822. PA DEP issued the Title V permit for the Armstrong power station in July 2001. PTX 1209.

B. Hatfield's Ferry

823. Allegheny submitted a Title V permit application to PA DEP for the Hatfield's Ferry power station in July 1995. PTX 1207.

824. The Hatfield's Ferry Title V permit application did not address the Hatfield's Ferry PSD Projects or identify as applicable requirements any BACT emissions limitations that would have been required as a result of those projects. PTX 1207 *passim*.

825. Allegheny certified that its Hatfield's Ferry Title V permit application was true, accurate and complete. PTX 1207 at AE_HQ_00591391.

826. PA DEP issued the Title V permits for the Hatfield's Ferry power station in November 2001. PTX 1203 at AE_HF00078631.

C. Mitchell

827. Allegheny submitted a Title V permit application to PA DEP for the Mitchell power station in July 1995. PTX 1213 at AE_HQ_00133328..

828. The Mitchell Title V permit application did not address the Mitchell PSD Project or identify as applicable requirements any BACT emissions limitation that would have been required as a result of that project. PTX 1213 *passim*.

829. Allegheny certified that its Mitchell Title V permit application was true, accurate and complete. PTX 1213 at AE_HQ_00133328.

830. PA DEP issued the Title V permits for the Mitchell power station in March 2002. PTX 1212 at AE_HF00079887.

X. PA DEP'S INSPECTIONS OF THE ARMSTRONG, HATFIELD'S FERRY AND MITCHELL POWER STATIONS

831. In Allegheny's RACT proposal for the installation of low-NO_x burners at Armstrong 1 and 2, Allegheny did not disclose the work that constituted the PSD Projects, including the replacement of the economizer, the convection superheater or the air preheater. PTX 1333 *passim*; PTX 1334 *passim*.

832. In Allegheny's RACT proposal for the installation of low-NO_x burners at Armstrong 1 and 2, Allegheny did not fully disclose all of the work that constituted the Reconstruction Projects, and in particular did not disclose the replacement of the economizer, the convection superheater or the air preheater. PTX 1333 *passim*; PTX 1334 *passim*.

833. In Allegheny's application for RACT plan approval for the installation of low-NO_x burners at Armstrong 1 and 2, Allegheny did not disclose the work that constituted the PSD Project, including the replacement of the economizer, the convection superheater or the air preheater. T.T., Sept. 23, 2010, at 216:3-21; PTX 253 *passim*.

834. In Allegheny's application for RACT plan approval for the installation of low-NO_x burners at Armstrong 1 and 2, Allegheny did fully disclose all of the work that constituted the Reconstruction Projects, and in particular did not disclose the replacement of the economizer, the convection superheater or the air preheater. T.T., Sept. 23, 2010, at 216:3-21; PTX 253 *passim*.

835. In Allegheny's RACT proposal for the installation of low-NO_x burners at the Hatfield's Ferry power plant, Allegheny did not disclose the pendant reheater project at unit 2. PTX 1216.

836. In Allegheny's application for RACT plan approval for the installation of low-NO_x burners at the Hatfield's Ferry power plant, Allegheny did not disclose the pendant reheater project at unit 2. T.T., Sept. 14, 2010, at 114:16-115:9, 122:8-18; PTX 1216 *passim*.

837. Allegheny did not otherwise tell PA DEP about the pendant reheater project at Hatfield 2. D.T. (Clark Colby 30(b)(6) witness on Hatfield projects), July 27, 2007, at 69:13-20.

838. In Allegheny's application for RACT Plan Approval for the installation of low-NO_x burners at the Mitchell power plant, Allegheny did not disclose the lower slope project at Unit 3. T.T., Sept. 14, 2010, at 122:19-22; PTX 1218 *passim*.

839. According to PA DEP records, PA DEP Air Quality ("PA DEP AQ") personnel conducted four inspections of Allegheny's power plants in 1995, 1996, 1997 and 1999 during

outages that are at issue in this case. DTX 634 (report of inspection during 1996 Hatfield Unit 3 lower slope project outage); DTX 834 (1999 report of inspection during Hatfield Unit 2 lower slope project outage); *see also* DTX 209.0005 and DTX 1449.0007 (identifying a December 12, 1997 inspection of the Hatfield's Ferry power plant that took place during the outage in which the Hatfield 1 lower slope and secondary superheater outlet header projects were performed; no report for this inspection has been located).

840. PA DEP AQ field inspector Chad Rittle conducted an inspection at Armstrong on September 22, 1995, during the outage for the Armstrong 1 Reconstruction and PSD Projects. DTX 557.

841. The purpose of September 22, 1995 inspection was to make sure the Armstrong boilers had installed low NO_x burners. D.T. (Charles Rittle, Jr.), Nov. 30, 2006, at 18:4:22.

842. Mr. Rittle began working at PA DEP as an asbestos inspector in 1994 when he received most of his training about asbestos. D.T. (Charles Rittle, Jr.) November 30, 2006, at 9:17-18, 10:23-23, 23:7-16.

843. At the time of his September 22, 1995 inspection of the Armstrong plant, Mr. Rittle was "relatively new to boilers." D.T. (Charles Rittle, Jr.), Nov. 30, 2006, at 18:25.

844. Mr. Rittle knew that a RACT permit that had been issued to the Armstrong plant prior to his September 22, 1995 inspection, but did not know what "RACT" means. D.T. (Charles Rittle, Jr.), Nov. 30, 2006, at 18:17-19.

845. Mr. Rittle did not know what else Allegheny was doing at Armstrong when they were putting in the low NO_x burners, other than removing asbestos. D.T. (Charles Rittle, Jr.), Nov. 30, 2006, at 19:18-24.

846. Mr. Rittle's September 22, 1995 inspection report does not indicate he was aware that Allegheny performed the following work at Armstrong 1 and 2 at the same time they were installing low NO_x burners:

(a) new components and reinforcement of boiler structure;

(b) new draft plant components (e.g., new air preheaters, new forced draft fans, among other things);

(c) new superheater area;

(d) new reheater area;

(e) new economizer;

(f) new boiler water wall tubes;

(g) new wind box;

(h) new burners, burner management system, and coal pipes;

(is) new penthouse;

(j) new vestibule;

(k) new ash hopper;

(l) new boundary and curtain air system;

(m) new over-fire air system;

(n) new soot blowers;

(o) new spray water systems;

(p) new boiler safety valves;

(q) new boiler controls; and

(r) new damper drives for the induced draft and forced draft fans.

T.T., Sept. 13, 2010, at 79:3-84:23; PTX 356 at R-3 22824 – R-3 22828; DTX 557 *passim*.

847. PA DEP AQ field inspector Bill Frioni conducted an inspection at Hatfield's Ferry on September 30, 1996, during the outage for the Hatfield 3 lower slope project. DTX 634.

848. The purpose of this September 30, 1996 field inspection was to conduct an annual RACT permit inspection incorporating the requirements of Plan Approvals 30-306-002, 30-306-003 and 30-306-004, issued for the installation of air cleaning devices (low NO_x burners with separated over fired air) on Units 2, 1 and 3 respectively. DTX 634 at AE_HQ_00405642.

849. Mr. Frioni's September 30, 1996 inspection report does not indicate he knew that Allegheny performed the following work at Hatfield 3 during the September 20, 1996 through December 1, 1996 outage: replacement of the lower slope tube panels, and replacement of the seal skirt. DTX 634 *passim*.

850. PA DEP AQ representative Bruce Fry conducted a CEM gas audit at Hatfield's Ferry power station on November 2, 1999. DTX 834.

851. Mr. Fry's inspection report from November 2, 1999 does not show that he entered the Hatfield's Ferry plant to conduct a general inspection, but instead it is an abbreviated inspection report showing numerical results of gas audits taken from tanks and stacks for NO_x and SO_2 CEMS. DTX 834.0002.

852. Mr. Fry's September 30, 1996 inspection report does not indicate he knew that Allegheny performed the following work at Hatfield 3 during the September 20, 1996 through December 1, 1996 outage: replacement of the lower slope tube panels, and replacement of the seal skirt. DTX 834 *passim*.

853. One cannot tell, just by looking at an activity inside a power plant, whether or not a PSD permit will be required. T.T., Sept. 14, 2010, at 100:2-11.

854. PA DEP AQ field inspectors were charged with determining whether Allegheny's coal-fired power plants were in compliance with existing permits. T.T., Sept. 14, 2010, at 88:20-25.

855. PA DEP AQ field inspectors were not trained engineers, but instead they typically had college degrees in a scientific field. T.T., Sept. 14, 2010, at 87:18-21.

856. PA DEP does not initiate the process of applying for air quality permits because air quality regulation is a self-reporting system wherein the applicant is expected to report and tell the agency everything that is happening. T.T., Sept. 14, 2010, at 97:6- 97:15.

857. It is the responsibility of the applicant to submit and obtain pre-construction approval from PA DEP. T.T., Sept. 14, 2010, at 97:22- 98:2.

858. PA DEP would not have the information about where the source to be constructed or modified was located but instead would have to receive that pre-construction information about a source from the applicant. T.T. Sept.14, 2010, at 98:2-4.

XI. <u>THIS LITIGATION</u>

859. On or about May 20, 2004, the Attorneys General of New York, Connecticut and New Jersey and the Chief Counsel of PA DEP sent a notice of intent to sue to defendants Allegheny Energy, Allegheny Supply, Monongahela and West Penn for violations under the Clean Air Act. Docket Item 430 ¶ 71.

860. On or about September 8, 2004, the Attorney General of Maryland sent a notice of intent to sue to defendants Allegheny Energy, Allegheny Supply, Monongahela and West Penn for violations under the Clean Air Act. Docket Item 430 ¶ 72.

861. Among other things, this notice described the PSD and nonattainment NSR claims that the plaintiffs are litigating in this action. *See* PTX 17 at 6 and PTX 18 at 6 (identifying PSD and nonattainment NSR claims for the Armstrong projects, Hatfield's Ferry projects and Mitchell lower slope project).

862. On or about August 3, 2005, the Attorneys General of New York, Connecticut, Maryland and New Jersey and the Chief Counsel of PA DEP sent a notice of intent to sue to defendants Allegheny Energy, Allegheny Supply, Monongahela, Potomac and West Penn for additional violations under the CAA. Docket Item 430 ¶ 73.

863. Among other things, this notice described the NSPS, BAT and Title V operating permit claims that the plaintiffs are litigating in this action. Docket Item 430 ¶ 73.

864. Each notice was served by certified mail on the EPA Administrator, the EPA Regional Administrator for the EPA Region in which the plants identified in the notice are located, the Governor of Pennsylvania, Allegheny Energy, Allegheny Supply, Monongahela and West Penn, and, in the case of the August 2005 notice, Potomac. Docket Item 430 ¶ 74.

865. More than sixty days elapsed between the 2004 notices and the filing of plaintiffs' original complaint in this action on June 28, 2005, in which plaintiffs' pled the claims identified in the 2004 notices. Docket Item 430 ¶ 75.

866. More than 60 days elapsed between the 2005 notice and the filing of Plaintiffs' first amended complaint in this action, in which plaintiffs' pled the additional claims identified in the 2005 notice. Docket Item 430 ¶ 76.

Dated: December 22, 2010

Respectfully submitted,

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